EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 170

DATE: Thursday, October 29, 1992

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, Thursday, the 29th day of October, 1992, commencing at 9:00 a.m.

VOLUME 170

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THE REGISTRAR: This hearing is now in session. Be seated, please.

THE CHAIRMAN: Mr. Watson, are you planning to do the complete examination of these two witnesses or are you going to do it in separate segments?

MR. R. WATSON: I'm going to deal with each one separately, sir. They are here as a joint panel. I'm going to do a summary of the evidence that was filed in Exhibit 742 and 743.

THE CHAIRMAN: I just wonder if it mightn't be easier if we did one -- they seem to have discrete -- am I right that they are discrete subjects, that they don't interrelate? Or do they interrelate?

MR. R. WATSON: There is some interaction, sir, in the same way that IPPSO panel was comprised of both Mr. Kinosian and Mr. Marcus I propose to do them one at a time and then they will both be available for cross-examination.

THE CHAIRMAN: I thought it might be easier perhaps if we dealt with one, and then give the cross-examination, and then dealt with the other, but I'm not worried about it. Whichever you prefer.

MR. R. WATSON: I think I prefer to deal

with them together, sir. I think there is some interaction there that might be helpful.

THE CHAIRMAN: All right.

MR. R. WATSON: Mr. Chairman, you are familiar with both Mr. Logan and Mr. Koppe. They have been with me on some of the cross-examinations of the Hydro panel.

I don't propose to go through their qualifications, their CVs are filed with the Board. I understand you have read their evidence in Exhibit 742 and 743 and today they will be summarizing their evidence and then be available for cross-examination.

The first witness will be Mr. Robert Koppe who will be dealing with life extension questions. Before we get into the substance of his examination, sir, there is typographical error in Exhibit 743, that's Mr. Koppe's filed evidence. On page 28, line 32, you will see there is a paragraph starting in the answer to Interrogatory 2.9.62.

The first "2" should be an "8", so that the Interrogatory No. reads 8.9.62. And of course that would also affect the additional witness statement of Mr. Koppe where he refers to the documents and exhibits he will refer to in this panel. Item No. 4G also should be changed from 2.9.62 to 8.9.62.

Now, Mr. Koppe --

THE REGISTRAR: Excuse me. Should I swear the witnesses?

THE CHAIRMAN: I think that's right. That's not a bad idea.

MR. R. WATSON: Please.

ROBERT H. KOPPE,
DOUGLAS M. LOGAN; Sworn.

DIRECT EXAMINATION BY MR. WATSON:

Q. Mr. Koppe, what's the purpose of your testimony today.

MR. KOPPE: A. The purpose of my testimony is to present the results of my review of Hydro's plans for life extension of their fossil plants.

Q. Can you summarize your major conclusions.

A. Yes, the conclusions are set forth in my prefiled testimony. But, briefly, I found that Hydro has not done a sufficient analysis to justify its life extension plans for those fossil units. Indeed on the available information the plants, just to life extend those units, appear to be uneconomical or at least marginally economical. Hydro has addressed an insufficient range of alternatives for the future use

of those plants and an insufficient range of new supply facilities.

In addition there are questions regarding the economics of Hydro's proposed environmental controls for those plants which themselves have a great impact on the economics of life extension.

Q. Mr. Koppe, how have Hydro's fossil life extension plans changed between the DSP and the Update?

A. They have changed considerably. Hydro's evidence in Panel 2 is largely contradicted by its evidence in Panel 8. While they continue in Panel 8 to assume that Lakeview, which will be very lightly loaded and would have very marginal economics for life extension would not be life extended, they are now assuming that the 12 coal units at Lambton and Nanticoke will have their lives extended beyond the planning horizon where previously they were assuming they would be retired at age 40.

Their load projections and planning philosophy as well as the expected retirement of Pickering "A" still result in the need for some new base load capacity around 2009 or 2010 but this change in assumptions about the life extension of Lambton and Nanticoke greatly reduces the amount of new base load

capacity that is needed in the 2010/2015 time frame.

Increasing the expected lives of the these 12 largest units is a major change and Hydro claims that there are four bases for these changes: one is additional experience in the industry; one is the results of the inspections at Lakeview; another is the initiation of life management programs at these plants; and the fourth one is the reduction in uncertainty as a result of their commitment to major environmental upgrades at these plants.

Q. And, sir, are these valid reasons for the change?

A. I do not believe so and I explain why in my testimony.

Q. And before a prudent utility makes a life extension decision, what should it do?

A. I think the main thing that needs to be done is to make a comprehensive economic evaluation of life extension in comparison with the alternatives.

Q. What factors need to be taken into account?

A. Simply stated, all you need to look at is the costs of extending the life and compare those to the cost of alternatives?

While that sounds simple it's actually

quite complex. For example, alternatives don't necessarily just involve shutting a unit down when it's 40 years old or extending its life. You could continue to run a unit beyond 40 years of age but not spend a significant amount of money on it and let its reliability deteriorate.

If you have a period of surplus capacity as Hydro is entering into, you could mothball the units for a while and reactivate them later, so there are a number of alternatives and the interactions among those alternatives can get pretty complicated.

Q. Sir, Hydro presented an economic evaluation of life extension at Lambton and Nanticoke. Could you describe that evaluation, please.

A. Yes, that's presented in a working paper that doesn't have a title but is dated February 7, 1992 and was provided in the response to Interrogatory No. 8.9.119.

THE CHAIRMAN: Just a moment. We better put that on record. 8.9.119.

Next interrogatory number?

THE REGISTRAR: 781.10.

---EXHIBIT NO. 781.10: Interrogatory No. 8.9.119.

THE CHAIRMAN: That's 8.9.119.

MR. KOPPE: They also presented spread

sheets which show the back-up calculations for that paper and those are in Exhibit 684.10.

In that evaluation they calculated levelized costs of producing energy from life extension of Lambton and Nanticoke and compared this to the levelized costs of a new combined-cycle unit or a new integrated gasification combined-cycle unit.

MR. R. WATSON: Q. Sir, in this paper what assumptions did Hydro consider when estimating of cost of life extension for these two stations.

MR. KOPPE: A. They did several parametric evaluations where they looked at how varying a number of assumptions would affect the results. And the main assumptions that they varied were whether the costs of adding scrubbers to these existing units should be considered a cost of life extension or not. What the costs of continuing to operate the units, that is to say, the life extension rehabilitation costs would be and over what time period the life extension expenditures would be amortized.

Q. Now, sir, if we could turn to the first of these assumptions dealing with the cost of scrubbers. What's the issue here?

A. I think the key thing to understand is that it doesn't make economic sense to install

scrubbers on fossil power plants that have low capacity factors. First off, such plants emit relatively little SOx. And, secondly, because you have a high capital cost associated with scrubbers, if you're only amortizing that over a relatively small reduction in emissions because the plant isn't operating that much, then the cost per unit of emissions averted becomes high. So it is much more effective to put scrubbers on plants with high capacity factors than do other things such as burning low sulphur coal in plants with low capacity factors.

[9:13 a.m.]

The reason this is important is that the capacity factor, say, for Nanticoke is expected to be very low over the next decade, and it is only when Nanticoke's capacity factor begins to rise in the 2000 to 2010 time period that it might make economic sense to put scrubbers on Nanticoke.

But at that point Nanticoke will be reaching near the end of its 40-year life, and so if Nanticoke is not to have its life extended then it wouldn't be economical to put the scrubbers on it at that point because there are only a few years of operation left, and you might rather want to have a new plant ready to go in say 2005 that would have scrubbers

on it, and then perhaps keep Nanticoke running but at lower capacity factors.

So, again, all of these things interact, but the assumptions as to what you are going to do with scrubbers importantly affect whether you should life extend a plant or whether you should retire it early or exactly how you should treat it.

Q. Sir, how does this affect the economics of life extension?

A. Well, I think to some extent I just answered that.

Q. You were dealing a lot with Nanticoke. Perhaps you could deal with Lambton to some extent?

A. Yes. The situation with Lambton is somewhat different because Hydro is already in the process of installing scrubbers on two units at Lambton and at least at the time I wrote this was about to commit to installing scrubbers on the other two.

Installing these scrubbers represents a significant fraction of the total costs of keeping these fossil units running over the next decades.

So once the money on the scrubbers has been spent the remaining cost to keep the units running becomes less and the economics of continuing to run

them becomes more favourable and life extending them becomes at least economically almost inevitable.

So the decision to put scrubbers on Lambton was in some very real sense a decision to extend their lives, although it wasn't evaluated in that way at the time.

Q. Sir, is it fair to say there is an interrelationship here between various issues?

A. Indeed, there is.

Q. Now, sir, did Hydro correctly account for the timing of the scrubber additions in their paper?

A. They assumed that since the scrubbers for Nanticoke would only be added if Nanticoke were to be life extended that for the purpose of economic evaluation they assumed the scrubbers were added just before the 40th year of life of those plants.

In fact, they are planning to, or were planning to, install those scrubbers on Nanticoke earlier in time and that would further increase the costs of the scrubbers, and they didn't account for that.

Q. Mr. Koppe, you have been talking about the costs related to environmental controls on Lambton and Nanticoke.

What is the issue with regard to other costs associated with life extension at these stations?

A. The estimated costs for life management and life extension at Lambton and Nanticoke that Hydro has presented in this proceeding are very low, and in their analysis I think they recognize that and consider it an alternative which involves substantially higher cost for those units.

Q. What is your view of the future costs related to life extension at these two stations?

A. I think it is inevitable that the costs will be higher than Hydro's projections, especially for Lambton.

Q. Sir, were there any other problems with Hydro's analysis of life extension costs?

A. They assumed that most of the expenditures for life extension would take place in year 40 and after. There were some modest costs earlier than that, but the vast majority of them, and especially in their higher cost case, were in years 40 and beyond.

In fact, power plants are not like the wonderful one-hoss shay; they don't run until they're 40 years old and then all the parts fall apart at the same time. Different parts of the plant wear out at

different times, and if you are going to keep a plant running for 50 or 60 years you won't wait until year 40 before you make equipment upgrades. You will do it as they become needed.

So, in fact, if you are going to run a plant beyond year 40 some of the money that you would spend to do that that you might not spend otherwise will actually be spent earlier than year 40, and since spending money earlier increases the levelized costs you would get higher levelized costs than they calculated.

Q. Sir, please summarize your evaluation of Hydro's assumed costs for life extension.

A. I think that the base case assumption - that is, their projected life extension costs in this hearing and the ones they used as the base case in their analysis - are completely unrealistic.

The alternative case numbers that they use appear quite realistic, but there is still some possibility of costs being higher than that.

Q. What should Hydro do to reduce that uncertainty about the costs for life extension?

A. The major uncertainties come about because of uncertainties in how long individual pieces

of equipment in these plants will last absent major upgrades or replacements.

So what Hydro really needs to do is to make the best estimates they can of the remaining lives of all the key components in the plants, estimate the costs of replacing or refurbishing each of those components, calculate how the plant will run if the components are replaced or if they are not, and combine all that information together to come up with a number of scenarios that indicate a variety of possible streams of expenses for maintaining these plants and what the resulting reliability of the plant would be under each of those scenarios.

The technology now exists to do that for major equipment. There are analytical procedures and inspection techniques for evaluating things like turbine rotors and generators and boiler tubes, and, in fact, Hydro is beginning to embark on a program to do that, but you really need the results of that to make an intelligent decision about life extension.

Q. Sir, the third assumption you mentioned was the time period over which life extension cost would be amortized. Could you elaborate on that, please?

A. In their evaluation Hydro considered

two amortization periods: one of 10 years and one of 30 years - in other words, a 50-year life or a 70-year life for the plant.

My own feeling is that the lives of these plants can be extended beyond 50 years, but because there is little experience with units over 40 years of age and no experience with larger units of that age, I think that one ought not to commit to life extension if it requires that these units run substantially more than 50 years in order to make it economically viable.

Q. Sir, leaving aside these three assumptions what alternatives to life extension did Hydro consider?

A. The only alternatives they considered were to retire Lambton and Nanticoke at age 40 and replace them with new generating stations, and specifically the new stations that they considered as alternatives were a combined-cycle station at lower capacity factors and then at the higher capacity factors in the 40 to 60 per cent range they considered an IGCC, an integrated gasification combined-cycle station.

There are two problems with those alternatives.

One is that there are a number of

plausible alternatives such as mothballing or early retirement that were not considered, and the other is that in the 40 to 60 per cent capacity factor range they compared life extension with an IGCC when their data shows that a new coal-fired station would be cheaper. And so that, of course, biases the case in favour of life extension.

Q. Sir, would you please summarize your views with regard to the economic evaluation of life extension at Lambton and Nanticoke?

A. I think that for Nanticoke the cost of scrubbers should be charged to life extension.

I think that the costs for life extension at both Lambton and Nanticoke will be higher than Hydro's base case, and I think that it is appropriate to base an evaluation of life extension on a 10-year amortization period.

When you take those assumptions and apply them to Nanticoke life extension using Hydro's February, '92 paper the costs of life extension of Nanticoke turn out to be somewhat higher than the costs of a new 4 by 800 coal station. So that would indicate that Nanticoke should not be life extended.

The 2/92 paper doesn't consider a lot of alternatives, and there is a great deal of uncertainty

about these costs associated with life extension.

I'm not prepared to say that life extension of Nanticoke would not in the end be economical, but there is enough uncertainty that I think a more thorough evaluation is warranted.

[9:25 a.m.]

Q. Sir, in your filed testimony you indicated that your experience was that life extension was usually cheaper than building new generation plants, except possibly at very low capacity factors. However, your preceding discussion seems to indicate that life extension at Nanticoke will likely be considerably more expensive than building a new fossil-fired station. Why is Hydro different from other utilities?

A. There are two reasons. One is that Hydro is planning to add more extensive environmental controls to their existing stations, to Lambton and Nanticoke, than any other utility in my experience.

And the second is that Hydro's cost for rehabilitation of these existing stations and for adding the environmental controls to these existing stations are considerably higher than is typical.

Q. Sir, dealing with the first of those issues, Hydro's plans for environmental controls. How

do they compare with other utilities?

A. They go well beyond those of any other utility in the United States certainly. And because Hydro is planning to do more and because their costs are relatively high and because the capacity factors of these units are relatively low, the cost-effectiveness, that is, the amount of money it takes to reduce a tonne of emissions is much higher for Hydro's plants than it is for the North American average typical plant.

Q. How do Hydro's plans for these environmental controls affect the life extension issue?

A. Well, if Hydro were planning to put such controls on a new unit but not on the existing units that would obviously favour a life extension of the existing units. But even when you are going to put the controls either on an existing unit or on the new unit that would replace it, the more controls you are planning on the more it favours a new unit because it's cheaper to put the same controls on a new unit than it is to add them to an existing unit.

Q. Sir, with respect to these environmental controls, what should Hydro be doing?

A. I think that before Hydro goes ahead with these environmental controls, they should evaluate

the alternatives. A lot of these controls, as I said, will result in reductions in emissions at very high costs. And society has alternatives which could reduce emissions at much lower costs. The expected costs of adding SCR to these coal units will cost in the tens of thousands of dollars per tonne of NOx emissions reduced while there still exist emission controls relating to automobiles, for example, that will reduce NOx emissions for hundreds or perhaps a couple of thousands of dollars per tonne.

So Hydro is planning, or was planning at least, to put on controls beyond what are required by regulation, I guess in the theory that this is in the public interest, but what they will actually be doing is spending society's money to reduce emissions when society is at the same time not taking other actions that would reduce those same emissions for much lower costs.

Q. Sir, why is all this important?

A. Well, I think in terms of the economics of life extension, it's very important to decide whether these controls are going to be put on Lambton and Nanticoke; and if they are going to be put on those stations, whether those costs are to be charged to life extension or not because without these

environmental controls then there is almost no question that life extension of Lambton and Nanticoke will be more economical in building a new station. With the controls the situation becomes much more marginal.

Q. Sir, the other point you mentioned was Hydro's higher costs. Can you comment briefly on this.

A. I have compared Hydro's costs for operating their fossil stations, for capital modifications to their fossil stations, for adding scrubbers to their existing stations, and for building new stations to typical North American averages and in all cases Hydro's costs are higher.

In the case of new stations, they are not very much higher, but in the case of these life extension costs and the costs of adding scrubbers they are substantially higher and that seriously impacts on the economics of life extension.

Q. Sir, would you please summarize your overall conclusions and recommendations.

A. Yes. My major conclusions are one, that the existing system is going to continue to be the major resource for Hydro for many years in the future and it's important that their decisions on investment and maintenance and life extension be sound and

economically justified.

Second, that the economics that determine the optimum life of a station involve a complex interaction among factors and that Hydro ought to more thoroughly evaluate those before they make decisions on life extension.

Third, the economic justification for the environmental controls program for these existing fossil stations has not been demonstrated.

Fourth, the analysis of the operation, of the life extension of Lambton and Nanticoke is incomplete.

Fifth, the budgeted expenditures for life management and life extension at Lambton and Nanticoke are inadequate.

And, sixth, that there is at least some chance that it might be economically optimal to retire some of these existing fossil stations before they are 40 years old or to mothball them and bring them back into operation later and that a complete evaluation of the economics of life extension should be undertaken before significant funds are committed on these plants.

Q. Sir, this Board has before it material that the Ontario Hydro board considered at their September and October meetings respecting the

capital program review at Ontario Hydro. How does this material affect your evidence?

A. I think the things that Hydro is proposing to do in here are in many ways similar to what I was recommending. I think they are reasonable responses to the situation in which they find themselves with the over capacity.

The thing that continues to concern me is that while they are now talking about deferring environmental controls on these existing stations, it seems to be more in response to the low demand rather than rethinking of this idea of overcomplying with existing regulations. And in the case of the life extension decision while the life management program would appear to be heading them in the right direction as far as a more thorough evaluation of life extension, I still don't actually see that in this memorandum.

Q. Thank you, Mr. Koppe.

Mr. Chairman, that completes Mr. Koppe's evidence. I will now start with Dr. Logan. If I could have one minute, please.

Dr. Logan, what are the major points that you will be making in your evidence?

DR. LOGAN: A. I have five main points. These points are, first, that Hydro's analytical

methodology for setting the target reserve margin is for the most part theoretically sound and up to date.

The second point is that there are three aspects of Hydro's practice that are however deficient. One of these aspects is Hydro's practice of picking the highest from a set of target reserve margins calculated under different assumptions. This yields a target reserve margin that is somewhat high.

The third point is that there is an issue with the way that Hydro solves for the optimal reserve margin that makes it systematically biased in favour of a higher target reserve margin.

My fourth point is that the third deficiency is that Hydro fails to account for the economic cost to customers arising from public appeals and voltage reductions. This emission yields a target reserve margin that is somewhat on the low side.

My fifth point is that the net effect of correcting for these three deficiencies is likely to be a reduction in the target reserve margin of about 3 per cent, from 24 per cent to 21 per cent.

Q. Sir, before you elaborate on any of these points, would you please summarize the practical importance of the reduction in the reserve margin described in your last point.

A. The primary effect of a reduction in reserve margin is to reduce the total amount of capacity additions required in the resource plan. This reduction usually occurs in the amount of new peaking capacity required, although there are some circumstances in which it could affect the total amount of base load capacity required too, but it's mainly in the peaking capacity.

Q. Sir, turning to your first point regarding Hydro's analytical methodology. Would you please briefly describe Hydro's method.

A. Hydro uses the value of service or VOS methodology for reliability planning. This methodology is described in Exhibit 87 and was investigated in detail in cross-examination of Hydro's Panel 2.

The fundamental concept of the VOS methodology is that reliability planning is primarily a matter of economics. Customers incur economic costs as a result of outages in electric service. The likelihood and severity of outages is reduced as the system is made more reliable. Therefore the benefit of additional reserve capacity is to reduce the expected cost to customers of outages. Reliability planning is a matter of trading off the economic benefits of

reduced customer outage costs against the cost of additional reserve capacity.

The optimal reserve margin is that which minimizes the sum of Ontario Hydro generation costs and customer outage costs.

Q. Is the VOS methodology appropriate for reliability planning?

A. Yes, it is.

Q. And many utilities use loss of load probability or LOLP as a reliability criterion. How does Hydro's practice compare to this?

A. LOLP is a reliability index calculated by probabilistic reliability models like Hydro's F&D model. However, LOLP indicates only the relative likelihood of a generation short fall and does not indicate the severity of short falls.

LOLP is typically expressed in terms like one day in X years, meaning that a generation short fall is expected to occur only one day over a period of X years. The calculated LOLP is compared against a criterion such as one day in 10 years.

So if X, the number of years calculated by the probabilistic model for a given configuration of the system, is less than the criterion value of 10, system reliability is deemed to be inadequate because

outages are expected to occur more often than they should.

Different reserve margins obviously yield different values of LOLP, so the target reserve margin is set at the level that yields a value of LOLP equal to this criterion, say one day in 10 years.

Now, a fundamental difference between using an LOLP criterion to set the target reserve margin and the VOS methodology is that the VOS methodology provides an economic basis for setting the target reserve margin while an LOLP criterion is based mainly on convention.

The common standard of one day in 10 years is based on tradition and the fact that utilities have operated with remarkable reliability after planning to this standard. But from the economic perspective of VOS reliability planning, reserve margins that satisfy this LOLP criterion are often far too high. The economic basis of the VOS approach used by Hydro is a significant advantage over traditional reliability planning criteria like LOLP.

Q. Sir, what are the shortcomings of Hydro's methodology?

A. Well, the three most significant shortcomings are, as I mentioned in the overview at the

beginning, their practice of picking the highest value of a range of optimal reserve margins. Second, there is a detail in the way that they calculate the optimal reserve margin for a given set of assumptions that is biased on the high side. And, third, their neglect of the costs of public appeals and voltage reductions.

Q. Dr. Logan, dealing with the first shortcoming respecting the various assumptions that Hydro analyzed, what range of optimal reserve margins does Hydro obtain from these assumptions?

A. They get a range of from about 20 per cent to about 24 per cent and these are shown in figures 5.1 and 5.2 of Exhibit 87.

Q. And what does Hydro do with this range?

A. Hydro picks the highest number: 24 per cent.

Q. How should Hydro account for the range of target reserve margins for the conditions and the years that they analyze?

A. Well, to the extent that there are uncertainties that cannot be adequately represented in a single F&D model run, it is appropriate to do several runs of the model, as Hydro does, and get the curve that is plotted in figures 2 and 3 of my testimony

which are from figures 5.1 and 5.2 of Exhibit 87. These curves expressing the worth of the CTU for each of these combinations of assumptions.

[9:50 a.m.]

But before calculating an optimal reserve margin these curves should be combined by weighting each of the curves according to its probability of occurrence in the same way that Hydro weighted two of its curves in calculating what appears as the 10 per cent probability curve in figure 5.2.

From this combined curve that was calculated by weighting the other curves they should then derive the target reserve margin. This will be somewhere in between the 20 and the 24 per cent numbers that they got from each of the curves separately.

Q. You say "somewhere in between". What figure would they obtain?

A. Well, I would guess about 21 or 22 per cent.

Q. Why is this approach preferable to Hydro's practice of taking the upper end of the range?

A. There are two kinds of risks in reliability planning.

One is a risk that can be modelled within a single run of the F&D model, and the second kind of a

risk is one that can't be modelled within one run but requires separate runs to represent.

An example of the first kind of risk, the one that can be handled within the F&D model run, is load forecast uncertainty; another is generation unit availability.

An example of the second kind of risk that can't be adequately captured within one run of a reliability model given the current state of the art is the issue about what is the proper hydraulic modelling method, and the second one is the modelling of common mode outages.

The fundamental concept of value of service is a weighing of the costs and the risks. The approach that I am advocating would treat the risks imposed by both of these kinds of uncertainties in a consistent way.

Hydro's approach treats those two kinds of risks differently. The ones that can be modelled within a single run get weighed by probabilities; the kind of risks that can't be modelled in a single run get analyzed on a worst case kind of a basis.

Q. Sir, let's turn to the second short coming. How is Hydro's method of solving for the optimal reserve margin biased in favour of a higher

target reserve margin?

A. The method for solving for the optimal reserve margin is illustrated in my figure 2, which is figure 5.1 of Exhibit 87. It might help if we could take a moment and turn to that figure.

MR. R. WATSON: If the Panel Members are looking at Exhibit 87 in lieu of Dr. Logan's exhibit the figure has been revised, figure 5.1, 5.2 and 5.3 have all been revised. So if you are looking at that make sure you have the revised edition.

DR. LOGAN: Realized by Hydro.

MR. R. WATSON: Q. Indeed.

DR. LOGAN: A. The value of the curve at any level of reserve margin represents the worth of a CTU, which is really the worth of an entire 672 megawatt block of CTU capacity, which is a change in reserve margin of about 2.2 per cent.

Now, because the worth of a CTU is declining as the reserve margin increases we know that the first 168 megawatt unit in this four megawatt block of 672 megawatts, this first unit has a worth that is higher than the average worth of the four units, and the fourth unit in the block has a worth that is lower than the average of the four units, but Hydro's methodology for constructing the curve assigns the

average worth of all four units to the point represented by the last unit.

It would be closer to the truth to assign that average worth, if you will, of all four units to the midpoint of the block which would have the effect of shifting the curve to the left by about 1.1 per cent. That is half of 2.2 per cent. To shift the curve 1.1 per cent to the left to correct this problem would yield a target reserve margin that is 1.1 per cent lower.

Q. Sir, if we could now turn to the third shortcoming you mentioned, the issue of voltage reductions and public appeals, could we have your comments on that?

A. Hydro has a sequence of emergency actions that are invoked when a shortfall of generation capacity is imminent. Three of these emergency measures result in unserved energy. These are voltage reductions, public appeals and rotating load cuts.

Of these three majors that result in unserved energy Hydro accounts for the cost of only one of them in setting the target reserve margin, and that is the rotating load cuts.

Q. What happens with the other two, the voltage reductions and the public appeals?

A. Hydro's F&D model calculates unserved energy from all three of the emergency actions, including voltage reductions and public appeals, but Hydro assigns a customer cost of zero to these other two majors. Thus, the benefit of increased reserve margin for reducing unserved energy from voltage reductions and public appeals is ignored.

Q. Why do they assign a value of zero?

A. Well, Hydro stated an official position in the Panel 2 cross-examination that these actions impose negligible costs on customers. However, they also admitted in cross-examination that there is internal division within Hydro on this point.

Q. Sir, do you accept that these actions impose negligible costs?

A. No. Hydro's Exhibit 87 on pages 103 and 104 states that some circuits were exempted from future voltage reductions because customers had actually experienced equipment failures as a result of voltage reductions in 1989.

Obviously, customers incur a cost when equipment fails, whether the equipment is actually damaged by voltage reductions or is merely temporarily disabled for the duration of the voltage reduction.

Q. What about public appeals?

A. Hydro takes the position that because customer curtailments resulting from public appeals are voluntary, then these curtailments impose no costs on customers.

I disagree with that position. Public appeals are in effect asking customers to make personal sacrifices for a limited time for the good of the larger community. Such sacrifices are not costless to the customer. The energy uses curtailed in response to these appeals may not be critical at that time, but the customer nevertheless is incurring a cost.

Q. What effect does this third issue of voltage reductions and public appeals have on the target reserve margin?

A. It is smaller than the other two effects, but I estimate that the target reserve margin would be increased by two-tenths, seven-tenths of a per cent if the cost of public appeals and voltage reductions were considered.

Q. Sir, what is the bottom line of your evidence?

A. Well, the bottom line of my evidence is that Hydro's methodology for setting the target reserve margin is generally sound but that a few deficiencies need to be corrected.

Q. What would be the net effect of the changes that you are suggesting?

A. Well, just to summarize briefly what those three changes are again, the first is a change of method for dealing with target reserve margins calculated for different assumptions. That would result in a reduction of 2 or 3 per cent in the target reserve margin.

The second is a change in the way that the block is handled in constructing the curve that would result in a reduction of about 1.1 per cent.

The third is to account for voltage reductions and public appeals that would result in an increase of two-tenths to seven-tenths. So the net effect would be a reduction of about 2.4 to 3.9 per cent in the target reserve margin.

Q. What do you recommend?

A. I recommend that Hydro's target reserve margin be reduced by about 3 per cent from 21 to 24 per cent.

Q. What is the practical consequence of this recommendation?

A. A reduction in the target reserve margin by 3 per cent reduces the amount of peaking capacity required by about 780 to 930 megawatts given

the load forecast for the years 1996 or 2014.

Now, if you take the annual cost of gas turbine capacity, which is about $43 per kilowatt as shown in that figure 5.1, you get that reducing reserve capacity by this number of megawatts multiplied by that cost per kilowatt translates to annual savings of $33 to $39 million a year.

Q. How does this affect system reliability?

A. Well, obviously if the reserve margin is reduced the overall reliability of the generation system will be diminished somewhat, but the economic evaluation underlying this reduction of reserve margin shows that the reduction in reliability is outweighed by the cost savings in terms of generation capacity.

Now, these cost savings could be reallocated to upgrading or maintaining the transmission system, which could result in an increase in reliability overall.

Q. Sir, you have been talking about the system reserve margin. Mr. Marcus was testifying on Monday, and he was speaking about a resource reserve margin.

In particular, at page 19 and 20 of his Exhibit 739 he refers to a resource reserve margin of

51 per cent for the nuclear common mode outage scenario. Could you comment on this, please?

A. Well, he's not saying that the system-wide reserve margin should be increased from 24 per cent to 51 per cent. His testimony doesn't address the system-wide target reserve margin at all.

Rather, he is saying that if Hydro built a new 4 times 881 megawatt nuclear station with a total capacity of 3,524 megawatts it would provide 2,339 megawatts of load meeting capability. This point, however, applies only to a 4 by 881 station.

Mr. Marcus admitted in a footnote on page 7 of his testimony that it doesn't apply to the single unit 670 megawatt configuration, and this would be true even if four 670 units were built on the same site.

Q. Sir, Mr. Lanzalotta for the Coalition testified on Tuesday, and his evidence on page 16 of Exhibit 744 referred to PG&E having had a target reserve margin as low as 12 per cent.

Is this type of a reserve margin that he is referring to comparable to Hydro's target research margin that we have been discussing today?

A. No, it is not. This 12 per cent number refers only to the short term. It does not refer to the long term.

Since the middle 1980s, when PG&E adopted the value of service methodology, PG&E has used a number close to 12 per cent for the target reserve margin, looking out only one year ahead. But that is applicable only to the short term. The long term number has been between 16 per cent and 19 per cent, and that is the number that is comparable to Hydro's target reserve margin.

Q. Finally sir, Mr. Lanzalotta, again at page 38 of Exhibit 744, talking about outage costs refers to a figure of $190,000 per kilowatt as an equivalent capacity cost.

Could you comment on this, please?

[10:05 a.m.]

A. Well, the point that Mr. Lanzalotta makes with the $190,000 estimate is wrong. He derives the $190,000 figure from the customer outage cost that we have see many times before of $5.91 per kilowatthour. Then he observes that the $190,000 number is ridiculous, so he concludes that the $5.91 number is at fault.

The $190,000 number is ridiculous, I agree with that, but the problem is not in the $5.91 outage cost estimate; rather, it's in another assumption that he makes and the comparison that he is

attempting to draw. He starts with the fact that the cost of power from a combined-cycle unit at 60 per cent capacity factor is $4.81 a kilowatthour -- I'm sorry, 4.81 cents per kilowatthour.

The construction cost of this CC unit is $750 per kilowatt, so he derives what the construction cost would have to be to make the cost of power increase from 4.81 cents to $5.91, and that's where he gets the $190,000 figure.

Now his mistake is in assuming that the $5.91 number is equivalent to 4.81 cent power. It is not. The 4.81 cent power is available day-in and day-out with a capacity factor of 60 per cent.

The $5.91 number represents power in an extreme emergency with a capacity factor probably of less than a tenth of a percent. If you use the capacity factor of this emergency power, less than a tenth of a per cent rather than a 60 per cent capacity factor of a combined cycle, then you would get a dollar per kilowatthour figure much, much less than a $190,000, a number that is more in line with the actual costs of building a power plant. Nowhere in Hydro's process is there a number like $190,000 or anything that can be reasonably extracted to $190,000.

MR. R. WATSON: Thank you.

Mr. Chairman, those are my questions. The witnesses are available for cross-examination.

THE CHAIRMAN: My list shows AECL as the first on the list. Are they here this morning? (No response.)

I take it they are not going to examine.

Then you are next, I think, Mr. Shepherd.

MR. SHEPHERD: Mr. Chairman, I don't expect to be long, perhaps a half an hour at most.

CROSS-EXAMINATION BY MR. SHEPHERD:

Q. Dr. Logan, can we start with you. Perhaps just a couple questions. Could you look at page 10 of your evidence, please.

There you talk about how Hydro has modelled common mode outages. And if I can paraphrase what you've said, it is something like this. Hydro has only modelled two unit outages which tends to understate the common mode effect, but they also use a sort of a crude weighting mechanism to get their final result and that overstates the effect, so the two things probably balance each other out. Is that about right?

DR. LOGAN: A. That's about right.

Q. I take it you will agree that it would be better to model the various common mode

effects directly rather than to use a short cut and assume that the flaws in the method cancel each other out?

A. Yes. That would be better to do a more comprehensive analysis.

Q. Okay. Could you turn then to page 13 of your evidence. There you talk about catastrophic events. I take your point there to be that it's not normally appropriate to include catastrophic events, what we have been calling in this hearing low probability high impact events, in the calculation of reserve margins. Why is it that you shouldn't include them in reserve margin calculations?

A. Reliability planning involves two general issues which are called adequacy and security. And adequacy relates to having enough capacity, either generation capacity or transmission capacity, to meet demands, recognizing that some of this capacity may be out of service for various reasons. That's the adequacy issue.

The other issue, security, relates to operating procedures and protection systems that prevent various events from turning into catastrophic blackouts.

The kind of events that I am talking

about are not just generation outages or transmission outages but system disturbances relating to lines or capacity, the moment that they go off-line, or failures of relays or all kinds of things. But these kinds of issues are dealt with under the security topic, and the adequacy topic just deals with the capacity. The kind of events that lead to security problems are not in general the generation outages.

Q. I'm going to state to you a proposition of general application and ask whether you agree with it. Okay. The proposition is this: For each potential cause of energy not served, that is, for each risk or uncertainty, you must make an explicit or implicit determination of whether that risk or uncertainty is best dealt with through the reserve margin. Only those risks or uncertainties that are best handled through the reserve margin technique should be included in that reserve margin analysis. The other risks and uncertainties such as catastrophic events still have to be dealt with in planning and costing but they are not appropriately considered in calculating the reserve margin; is that correct?

A. Yes, you are saying that you sort out the risks between those within the reserve margin and those dealt with other ways.

Q. If I might just take this to a simple example. It took me about half an hour to figure out what seems to be fairly common sense.

If, let's say, some sort of defect was found in all CANDU reactors so they all had to be shut down immediately, just say that happened, that's not something you can deal with in a reserve margin; right? The reserve margin isn't going to help you there so there is no point in including that sort of possibility in your calculation of your reserve margin?

A. Well, that's an extreme hypothetical.

Q. Understood.

A. Quite extreme. If you recognized it as something that wasn't so extreme, then perhaps you would want to include it. But given the extremity and some other mitigating things, I would say it should not be included within the reserve margin.

Q. Isn't the reason for that that you would be incurring an economic cost, increasing your reserve margin to deal with the problem, but when the problem actually happens you still have the blackouts in that particular example?

A. Well, you are not going to have a catastrophic blackout like we were just talking about. You may have rotating outages.

Q. Okay.

A. But I'm making a distinction here between the catastrophic blackout which I was referring to on page 13 or whatever it is and rotating outages, which hopefully prevent a catastrophic blackout. But the reason for not including this extreme scenario that you have postulated is that there are mitigating things that would prevent it from happening.

Q. Sorry, you don't include it in the reserve margin because you can prevent it from happening, so it's not a risk?

A. Well, if a design flaw was found in CANDU units that - going back to your example again - would require all 20-some operating units to be shut down to be corrected, I find it implausible that regulators in Ontario or in the federal government would require all 20 reactors to be shut down to be repaired immediately.

If you look at Mr. Marcus' testimony, I don't recall the exhibit number but it's included in the reference package where he does the analysis of the lead time delays, he lists the units that are operating and when they came on line, if you add up the years that all of those units have been operating, you come up with a number that is close to 200 reactor years of

experience. It is nigh implausible that after nearly 200 reactor years of experience a design flaw would be found that would provoke any rational person to say that you have to shut down all of these reactors immediately and correct them all at once. It's much more plausible that if such a flaw was found that the regulatory authorities would stagger the requirements for outages to repairs in order to manage the outage costs imposed on customers.

Q. I don't intend to get into a debate with you about whether nuclear stations could have problems. If you accept the hypothetical -- maybe I can put this another way because the point is quite a simpler one and I'm sorry the example got us into this mess.

If you accept the hypothetical that it is possible, however low the probability, that we could find out tomorrow that there is some safety-related issue in CANDUs that cause AECB to say, you have got to shut them down right now; they're too dangerous. Or the government to say that or whatever. If you accept for a moment that's a very low probability but conceivable, the reserve margin can't protect you against that, can it?

A. An ordinary reserve margin cannot

protect you against that kind of a scenario.

Q. Thank you.

My last point for you relates to the value of service methodology which as you have said is the same, you are talking about the same thing as Ontario Hydro is, value of service is a common part of your methodology?

A. Yes.

Q. And it's true, isn't it, that the customer damage function, that is the customer cost that you are talking about, varies widely by customer class?

A. Yes.

Q. So for example a very sensitive industrial user might consider the marginal cost of unreliability to be $10 a kilowatthour and a residential customer might think it's only a few cents a kilowatthour; right?

A. Yes.

Q. And what you do in a customer cost-driven calculation is you weight all of those customer costs by usage to determine -- if I can oversimplify a bit, you try to figure out how much should we spend on getting a reserve margin, so you add up the costs to everybody of getting a particular

reserve margin to balance them out; right?

A. Yes.

Q. Okay. Sort of like an insurance premium almost; isn't it?

A. That's what it is.

Q. Okay. So let me just try some simple math. Hypothesize a simple system in which there is only two customer classes; they have equal usage. Class A, let's say that is industrial customers, has a cost of unserved energy of $9 a kilowatthour. Class B, which is residential, has a cost of $1 per kilowatthour of unserved energy. And the total cost to maintain the reserve margin each year is $100 million.

I understand the real calculation is more complicated this, but in fact in simple terms $90 million of that $100 million is being paid to protect Class A and $10 million is being paid to protect Class B; is that fair?

A. Yes.

Q. Do you know of any utilities in North America that base their customer rates by class on the relative values to the different classes of the reserve margin?

A. I know that there are utilities that have been talking about doing that. I am unclear

whether any of them have actually gone all the way through to actually base rate design on differences in value of service between the classes.

Q. Are you aware of whether in Ontario the costs of the reserve margin are allocated in this way as between customer classes based on cost of unserved energy?

A. I'm not familiar with rate design in Ontario.

Q. Okay. If in order to protect themselves against their perceived cost of unserved energy, a particular class of customers were to say to a Board like this or Hydro or whoever, the government, please build some more generation to protect us, do you believe it would be appropriate for that class to bear the cost of that?

A. I recognize a plausible argument there.

Q. I won't push you any farther than that.

Mr. Koppe, let me turn to you.

Let me just clear up a couple of things about your background and qualifications. From 1968 to 1974 you were manager of ConEd's nuclear engineering division, right, Consolidated Edison's nuclear

engineering division, and during that time your main responsibility was to get some nuclear stations that were being built on line; right?

MR. KOPPE: A. That's oversimplifying the case. I was responsible for licensing of those stations. Other people were responsible for building and starting them up.

Q. Although you were in charge of the division; right?

A. Of the safety and licensing division, so I was doing safety analyses and responsible for dealing with the regulators. I was not actually in charge of the construction or the startup.

Q. Can you confirm, please, that during that period and as a direct result of nuclear construction cost overruns and delays, Consolidated Edison had to suspend its dividends and its bonds were derated basically down to a junk bond level; is that correct? I know it's a long time ago.

A. Yes. And ConEd, the financial catastrophe that hit ConEd was just after I left. I'm not sure if there is a correlation there or not.

[Laughter.]

Q. I would never suggest that.

A. But the truth is I can't remember for

certain, but the two units that ConEd was building at those times were turnkey units and so while there were substantial cost overruns in building those units, Westinghouse was swallowing those overruns. ConEd got those units for incredibly cheap prices and so I wouldn't -- I truly don't remember. I was not primarily interested in ConEd's finances but I would not have said it was the nuclear plant problems that caused the financial crisis.

Q. Okay. You also note on page 2 of your evidence that you were involved in a Zimmer plant. That's the plant majority owned by Cincinnati Gas and Electric; right?

A. They were the construction managers. There were several owners. I don't think they owned the majority but --

Q. Okay, one of the owners.

It's true, isn't it, that the Zimmer plant was built as a nuclear facility but well into the construction so many problems were found that it had to be converted into a coal-fired facility because it would never be licensed as a nuclear facility; isn't that right?

A. That again is oversimplifying a bit, but indeed it was abandoned as a nuclear facility and

converted to coal. My involvement was evaluating the conversion to coal. I had nothing to do with the nuclear.

Q. Could you turn to page 5 of your material. At the top of that page, let me get it out too, at the top of that page you describe some of Hydro's assumptions as set out in the original DSP for not life extending fossil.

[10:25 a.m.]

And if I might simplify the first two, they are lack of experience with older plants, and changing regulatory provisions that might increase costs in the future.

I take it from your later comments that you agree with those assumptions and believe, contrary to Hydro, that they are still true - dealing with the first two?

A. Yes, I understand.

Those are considerations in trying to determine whether a plant should be life extended. When Hydro put those forth as reasons for assuming that the plants would be retired after 40 years I did not agree with that, and while if it weren't for the very high costs of these plants I would believe that life extension is the right thing to do with them, I don't

think that either of the situations with regard to these two points has changed enough to justify Hydro's change in position.

Q. It is still true that they have no experience with large units in the older years; correct?

A. That is true.

Q. It is still true that changing regulations could add significantly to costs; right?

A. That is still true.

Q. And those facts are also true today in case of nuclear generation for Ontario Hydro; aren't they?

A. Yes.

Q. If you could turn then to page 8... I am looking at line 22, and I thank you very much for including the lines in this. It makes things so much easier.

At line 22 you summarize the cost/benefit balancing that should be done for life extension. I take it you will agree that among the costs associated with either of the life extension or any of the alternatives would be any value or cost assigned to environmental or social externalities; correct? If there is a decision that emissions are worth something,

then in your cost/benefit analysis you have to include that number; correct?

A. I think there is significant disagreement as to whether and how the value of externalities should be included in evaluating alternatives.

If we take your supposition that these things should be included, then of course they should be included, but I do not have an opinion on that particular subject, and I know there is a lot of controversy and a lot of discussion about whether that should be done and what value should be used, but it is not something that I have worked in extensively.

Q. Yes, I understand that, and I'm not asking for your opinion on whether externalities should be given hard values.

I am asking whether it is fair to understand what you are saying in here as when you do a cost/benefit analysis every number that you consider to be a hard number should be in it.

If we make a policy decision that externalities should be considered to be hard numbers they have got to be in it, too; correct?

A. I think you are asking me a circular question. You are asking me if we decide to include

externalities in evaluation should we include externalities in evaluations, and the answer of course has to be "yes".

Q. All right. You have talked about life extensions and your experience being cost-effective more often than not; correct?

A. Yes.

Q. Would it be fair to say that if this jurisdiction adopted the sort of externality values for coal emissions in the order of 2 or 3 cents that are common in some jurisdictions - not all but some - that it would be very unlikely that life extensions would be economic in most cases?

A. In the few cases I have seen of externality values for coal plants they are substantially lower than 2 or 3 cents a kilowatthour.

If you adopted numbers that high then coal plants new or old would not compete with nuclear or gas or lots of other things.

Q. Okay. Let me take you to pages 13 and 14 of your evidence. On those pages you are talking about Hydro's Lambton estimates, and I take your conclusion there, eventually on page 14, to be that Hydro's projections for Lambton expenditures in the future are not only suspect but they may in fact be

wrong by as much as perhaps an order of magnitude. They are far, far wrong.

Is that a fair analysis of your conclusion?

A. With respect to the base case assumptions--

Q. Yes.

A. --which Hydro has admitted are only costs for inspection and analyses and do not include allowances for actual modifications.

So, I don't think that Hydro was proposing those base case numbers as a realistic estimate of future costs. But with that caveat, given the history of Lambton and Nanticoke and unless something changes radically at those units, those stations, then I would expect actual costs to be significantly higher than the base case costs.

Q. But the base case is what they used in their cost/benefit analysis, isn't it?

A. They used two cases. They used the base case and then they used a higher cost case, which was much higher.

Q. But your view appears to be that the real numbers are probably even higher than their higher cost case.

A. I said they might be. I/am caught in some ambivalence here because when I look at the costs for plants similar to Lambton and Nanticoke in the rest of North America, the costs while they are somewhat higher than Hydro's base case are not nearly as high as their upper case.

On the other hand, the historical costs at Lambton are as high or higher than the base case, and so what we need to know is whether the continuing costs at Lambton and Nanticoke are going to be comparable to the costs that Lakeview and Lambton have seen in recent years or whether they are going to come back to something closer to a typical value.

And I don't know what the answer to that is.

What I am trying to point out here is that the answer to that question will affect whether it is economical to life extend these units, and so we ought to know what that answer is before deciding what to do with them.

Q. So ultimately, then, you are not saying that any of your calculations or anybody else's calculations for that matter, including Hydro's, are right.

What you are saying is the numbers are

all over the map and the only thing we really know for sure is that none of them have any basis in proper analysis - in a thorough analysis, sorry.

A. The specific projections for Lambton and Nanticoke do not have a basis in what I would consider to be a proper analysis. That is correct.

Q. Okay. On page 16 of your evidence, and I am looking at line 39 here - this is just a small point but it jumped out at me - you cite Interrogatory 8.9.19 as saying that 100,000 hours is about the time when deterioration really begins for a coal station like Nanticoke.

Is this number of 100,000 operating hours, is that a realistic benchmark or sort of rule of thumb of when deterioration starts in this sort of station?

A. Hydro appears to believe so, and there is nothing that I have seen in the specific plants that I have evaluated or in the industry data that I have looked at that would indicate that that is the case.

That isn't to say that some particular part of a plant might not wear out after 100,000 hours, but looking overall at coal plants, oil plants, nuclear plants, I do not see any significant deterioration in

the performance of any of those kinds of plants with increasing age.

Either after 100,000 hours or 150,000 hours or any other time as far out as the data go, which is between 20 and 40 years depending on which class of plants you are looking at, performance of all classes of power plants in North America, both nuclear and fossil, small and large, new and old, will have all been essentially constant with age.

Q. Could you turn to page 21, please? Here you are talking about - I am looking at line 26 - you are talking about what you just discussed a minute ago, that Hydro appears to make, at least in these cases, major capital expenditure decisions without a proper cost/benefit analysis.

In your review of Hydro's material, their reports, et cetera, filed in this hearing and in preparation of your testimony here, did you see any pattern at Hydro making major expenditure decisions relating to the existing system without proper analysis? Does there appear to be any apparent pattern there?

A. The decisions that I have reviewed, which are primarily the rehabilitation expenditures and the environmental control expenditures for the fossil

units, I didn't see any, what I would consider to be, appropriate cost/benefit evaluations.

Q. Okay. If you could move then on to page 25 here you are discussing the difference which you have discussed also in your direct oral evidence today, the difference between what Hydro is spending to reduce emissions on a per unit of emission basis per tonne, say, and the sorts of values that have been assigned to those emissions by market forces in the United States.

Let me first take you to the U.S. situation.

The values of emissions trading permits in the United States are driven by market forces; correct - largely?

A. No, that is not correct. They are driven primarily by the value of the cap that is set on emissions.

Q. Okay. Yes.

A. And by technology. The market simply works to move the price of emissions to the marginal cost of control that is set by the combination of the technology and the cap.

Q. So if you have a very high cap - that is, you basically say, emit all you like - then

emissions trading permits aren't going to be worth very much because it doesn't cost very much to simply reduce your emissions; right?

A. No, it's because very few people have to reduce emissions --

Q. Or --

A. And so the ones who can do it most cheaply are the only ones who do it.

Q. And conversely, if you have a very, very tight cap the value of having the right to emit is higher; correct?

A. Yes.

Q. So when you are doing your comparison of the United States and Canada presumably one of the things that is important is the extent to which in Ontario, say, we do or do not want to be stricter in our control of emissions; correct?

A. Yes.

Q. That is a policy decision, right; it is not an economic decision?

A. Exactly.

Q. So when you talk about -- when you criticize Hydro for spending more than the U.S. numbers that is only relevant if we assume that we have exactly the same standard for emissions as in the United

States; correct?

A. No, I think that is not correct for two or three reasons.

First, when Congress set the cap in the 1990 Clean Air Act Amendments they had estimates of what they thought would be the marginal cost of control.

The fact that they set the limits where they did is indicative that they thought that that expected marginal cost of control was roughly the value of reducing emissions.

So you have -- the U.S. experience gives you a piece of data as to what regulators, legislators in the United States felt was the value of reducing SOx emissions. So that is one point. The second point --

Q. Excuse me. But before you go on, does that imply then that regulatory or government controls here are not based on any proper analysis; we should just follow what Congress said?

A. That does not necessarily imply that at all.

In fact, I think that the regulatory limits right now in Ontario are fairly comparable to the U.S. limits. Ontario has basically cut SOx emissions in half, which is what the United States is

in the process of doing. So I think that the current regulations in Ontario and the current regulations in the United States are fairly -- as consistent as one can get in this sort of thing.

So that is one point.

Another point is that to the extent that there might still be in Ontario other ways other than installing scrubbers at Hydro's plants to reduce SOx emissions for lower costs those would be preferable. I don't know if they exist or not. I do know that someone in Hydro's Panel 2 - I believe Mr. Taborek - indicated that he believed that at least some of the smelters in Ontario could still reduce SOx emissions for costs per tonne that were less than Hydro.

So if in the course of considering these issues the government of Ontario considers that it is worth more money to reduce SOx than the U.S. Congress thought it was and wants to impose that on Hydro then Hydro will have to do it.

But what I am arguing with here is Hydro right now is planning to overcomply with existing regulations and reduce emissions at costs per ton that are much higher than what other people are currently thinking is worthwhile and that they shouldn't do that without considering whether indeed it makes sense for

the people of Ontario.

Q. That's interesting. I take it you are not saying that Hydro should make sure that they are always at their regulatory limit and never try to get below it?

You would agree with the principle that to the extent that you can emit less than the regulations require, you should; correct?

A. No, I would not agree with that. You may have to emit somewhat less than the regulations in order to ensure that as in the natural variations of things you don't exceed the limit, but the regulations -- the government as a whole ought for the province or the country or whatever we are talking about as a whole, decide what is the societally optimal level of controls and ought to apply that uniformly to everybody, and then everybody ought to comply with it.

Ontario Hydro shouldn't go out and say we are going to be good guys and even though the government has decided that the people of Ontario should only pay $500 a tonne reduce SOx we are going to go out and spend $1,500 a tonne of our rate payers' money to reduce SOx emissions. I don't think that is right at all.

Q. Would you say that is true in the

private sector as well.

Let's say, take a company like Inco, for example. If there are no regulations on, say, their NOx emissions that they should then not make any attempt to reduce their NOx emissions because the government has not spoken and told them to?

A. Yes, I think that's right.

Q. Finally, the last, I guess, area I want to deal with, if you could turn to page 29 of your evidence in your overall conclusions at pages -- I'm sorry, at lines 28 to 31 you say: It is important that decisions regarding the appropriate investment in maintenance and life extension of the existing facilities be as sound and economically justified as investment in new resources.

I take it that this isn't limited to coal life extension but any major expenditure on the existing system, coal, nuclear, transmission, hydraulic whatever, requires that same rigourous analysis and sound base; is that correct?

A. Yes.

Q. If you look to lines 34 to 36 you say with respect to life extension: Those decisions should be deferred until...in effect Hydro does its homework; correct?

A. Yes.

Q. Does that also apply to other major expenditure decisions?

A. Yes.

Q. Now, I guess the question that that raises - this is the hard question - is the longer-term implications of that.

This Board isn't being asked to decide should you spend some money next year. This Board is being asked to decide should we build new nuclear stations or should we get more demand management, things like that.

I guess the question is: If you are in the position of this Board or a planner trying to make a decision and the proper analysis hasn't been done on the existing system how do you deal with that in making your new generation decisions? What recommendations do you have for this Board as to what should be done in that regard?

A. Well, I think the obvious answer is to get as close to the right kind of analysis as you can get within the time frame and authority that the Board has.

[10:38 a.m.]

I don't know the mechanisms for how to do

that, but this hearing goes on for long enough that one has a certain amount of time to try -- it may not be a perfect analysis but to do the best that's possible within the time frame.

Q. So you would suggest then that this Board say today, for example, or next week or whatever, got another year to run, you have time to do the analysis, Hydro go away and do the analysis, and come back with it before we are finished. Do you think that's the appropriate result?

A. That's what I would do.

Q. Okay. Let's presuppose that that isn't done. That you are at the end of the day now, you still don't have the proper analysis. What do you do? Do you assume that those life extensions will be there because that's what Hydro says and therefore don't give any approvals? Or do you assume that they won't be there because there is some possibility they won't be there and therefore give a bunch of approvals for new generation? What do you do?

A. That's not a question I have thought about a great deal. And I guess if I were omnipotent I would give contingent approvals.

Q. So you would say, for example, go ahead and build another nuclear station but before you

do it make sure this analysis has been done on your coal life extensions and if they prove to be economic then you can't build a nuclear station?

A. Something like that.

MR. SHEPHERD: That sort of thing?

I have no further questions.

THE CHAIRMAN: Mr. Poch, I guess you are next and then is there anyone else? Mr. Greenspoon; is that right?

MR. GREENSPOON: I might have a short question.

THE CHAIRMAN: Anyone else? (No response.)

We'll take a break now for 15 minutes.

THE REGISTRAR: Please come to order. This hearing will recess for 15 minutes.

---Recess at 10:43 a.m.

---On resuming at 11:00 a.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Be seated, please.

THE CHAIRMAN: Mr. Poch.

MR. D. POCH: Thank you, Mr. Chairman.

CROSS-EXAMINATION BY MR. D POCH:

Q. Panel, I represent the Coalition of Environmental Groups for a Sustainable Energy

Development.

Mr. Logan, I would like to start with some questions for you. You recommend 21 per cent for the reserve margin. You include about 20 per cent for reasons similar to Ontario Hydro, having corrected in the ways you said you did, and then you add back in roughly .2 to .7 for the social cost of voluntary load reductions by customers in response to public appeals which rounds off at about 21; is that a fair characterization?

DR. LOGAN: A. Yes.

Q. So while utilizing a different approach, that is the F&D or value of service approach, your answer is quite close to Mr. Lanzalotta's 20 per cent and perhaps we could even attribute the difference that exists to this consideration of public appeals related costs accounting for this up to .7?

A. The number is close. There are some substantial differences between his analysis and my analysis but the result is close

Q. All right. We received answers to Interrogatories B9.7.24 to B9.7.27, which related to your portion of the evidence. Do you adopt those answers as yours?

A. I would need to look at them.

Q. Okay. Perhaps you could get them out. Let me ask my counsel, are they in this binder?

THE CHAIRMAN: Can we get them out. Do we have them? Are they available?

MR. D. POCH: I assume the witness has them.

THE CHAIRMAN: I mean to us. Can they be given one number.

MR. D. POCH: Yes. Mr. Chairman, in fact I'm going to have a similar question for Mr. Koppe. In fact, the series of interrogatories that CEG has asked of MEA run from B9.7.1 through 27 inclusive.

THE CHAIRMAN: Why don't we put that in as one number then if you are going to deal with each one of them.

MR. D. POCH: That's fine.

Perhaps we can get a number.

THE REGISTRAR: Give me those numbers, please.

MR. D. POCH: B9.7.1 through B9.7.27 inclusive.

THE CHAIRMAN: That can be given one number.

THE REGISTRAR: 781.11.

---<u>EXHIBIT NO. 781.11</u>: Interrogatory Nos. B9.7.1 through B9.7.27.

MR. D. POCH: Mr. Chairman, when I actually get to some specific interrogatories that I'm asking the witnesses about today I will provide copies to everyone.

THE CHAIRMAN: Has Mr. Argue got a package there because we might as well get them.

MR. D. POCH: Yes. He has got the, the first, I think, 23 of those in a package without the various attachments.

DR. LOGAN: I don't seem to have a complete set here. I know that the ones -- oh, maybe they are here. I'm sorry, 21....

MR. D. POCH: It was 24 through 27.

DR. LOGAN: 24 through 27.

THE CHAIRMAN: Gentlemen, we don't have 24 and 27. We have everything else.

MR. D. POCH: Mr. Chairman, I think that's right. They weren't included in the package because I don't intend to get into them in detail.

DR. LOGAN: And your question was?

MR. D. POCH: Q. I just want to be sure that you adopt those answers.

DR. LOGAN: A. Yes.

Q. Now I think you may be aware that Mr. Lanzalotta was unable to run Hydro's F&D model and so he turned to the LOLP approach. And I take it, am I correct in taking that you prefer the F&D approach but the LOLP using the one in 10 years has given in your words "remarkable reliability"?

A. Remarkable, yes.

Q. Now, from 9.7.26 we just simply asked you there if you ran F&D and you said you didn't.

A. That's correct.

Q. Did run any alternative model?

A. No, I did not. I relied on the results of F&D model runs that had already been done by Hydro, detailed results that Hydro provided.

Q. You advocate counting customer costs of curtailment, voltage reductions, and so on. Are you comfortable with Hydro monetizing this what I will call externality when determining the appropriate reserve margin?

A. It's accounting for costs that are incurred by their customers. That's appropriate to account for that.

Q. You would agree then that this is an externality and it's one that you are comfortable monetizing and including; is that fair?

A. Well, it's not an externality to Hydro's customers. It is not a cost that is incurred directly by Hydro but it is a cost incurred by their customers.

Q. You would go further than Hydro and include something to account for the inconvenience of voluntary reductions, for example; fair?

A. Yes.

Q. That may not be strictly speaking directly costable but you are comfortable that you could impute a value to that; is that fair?

A. You can measure through various means the costs incurred by electricity customers to interruptions; and this other thing, voltage reductions and public appeals, is one that Hydro has neglected so far but it can be analyzed in a similar way to the rotating load cut cost that they do consider.

Q. Well, let me say to you. I took the phrase "externality" in fact from AMPCO' counsel who in a question to my witness characterized it as such. Are you uncomfortable with that phrasing?

A. Strictly speaking in economic terms an externality is something that appears on somebody else's bottom line but not on the decision makers' bottom line. So, I suppose strictly speaking it is an

appropriate term in this case.

I guess what I was reacting to is, sometimes externality takes on a much bigger meaning and I wasn't, I don't know if I'm quite ready to adopt that whole broader connotation in connection with the narrower view of these outage costs as being things incurred by Hydro's customers.

Q. So you were content to monetize and include externalities in planning and decision making to the extent that the bottom lines or the impacts are affecting either Hydro or its customers and you don't want to go beyond that; is that fair?

A. Yes.

Q. All right. You are aware that most everybody in Ontario is a Hydro customer?

A. One way or another I suppose that's true.

Q. Fine. We probably don't have too much of a difference then.

Are you concerned that the externality costs that you would have included are maybe difficult to quantify and in fact that the estimated costs have varied widely from survey to survey or year to year within customer classes and between customer classes. Does that give you pause?

A. I didn't say they were easy to measure and you are correct in observing that over the years there has been quite a bit of variability seen, but also over the years there has been quite a bit of development in the state of the art of assessing customer outages and I think that less variability is seen in the average estimates anyway now than was seen say in the 70s or early 80s.

Q. Are you concerned that the effect of including that particular externality is that it will tend to increase Hydro's investment and thus its price based on inclusion, evaluation and inclusion of those externalities, but that competing fuels may not include such evaluations? Does that dissuade you or are you satisfied that it is appropriate?

A. Well, it's not a matter of including or excluding that externality. It's a matter of two different ways of accounting for reliability. One is to use an a priori constraint like one in 10 LOLP; or the other is to try to derive an optimal reserve margin.

Q. Well, leaving aside the two methods for counting that cost or that benefit, one more explicit than the other, certainly however you count it with LOLP assumptions or with value of power surveys,

would you agree the effect is you are recognizing an impact on customers and therefore incurring some costs to avoid that impact? Or to mitigate that impact, sorry, you can't avoid it? That's the exercise here?

A. Well, providing a system with no reserve margin costs less than providing a system with a reserve margin, yes, if that's what you are asking.

Q. Are you concerned that other fuel vendors might not be spending as much for reliability or counting these externalities at all or to the same extent and that this is skew to be avoided or are you content that this is a real cost and to the extent we can count it we should?

A. Well, when you say other vendors not including this externality, are you saying that other vendors may not be providing a similar kind of a reserve margin?

Q. That's right.

A. And the alternative fuels that you are referring to are things like--

Q. Whatever they may be.

A. --gas or fuel oil or something like that?

Q. Fine.

A. In the case of the other fuels there

is not as critical a need for a reserve margin as for -- well, there is a need for a reserve margin but it's a different kind of a reserve margin. Other fuels can be stored while electricity cannot, so you have to -- all suppliers need to have some way of accounting for uncertainty in demand or shortages in their supply.

Q. Or other contingencies on their system?

A. Yes.

Q. And I'm just asking you: Are you worried that unless you examine to see to what extent they're valuing the service or the uninterrupted service of their product, unless you are satisfied that they are going to the same extent as Hydro that there might be a skew or are you content that is a second order concern and shouldn't dissuade us from counting those costs to Hydro's customers in setting reserve here?

A. I'm content that there is not a problem there.

Q. Have you examined that in detail or you believe the problem if of such magnitude that you don't need to be worried about it?

A. The latter.

Q. All right. Thank you.

Now what about customers providing their own backup power systems with or without Hydro's assistance. Did you look at that?

A. I did not look at that specifically in the course of this study. However, when you do surveys of the kind that assess customer outage costs, the costs of backup power do play a roll there for customers that have that alternative.

Q. Some may choose not to put in backup and so they would have higher costs of interruption then?

A. The cost of backup can be regarded as an upper bound on the costs that the utility should consider.

Q. Well, are you aware that the vast majority of outages on the Hydro system or to actual customers are due to transmission and distribution outages rather than generation outages?

A. Yes.

Q. All right. And so backup on-site has the added value of avoiding the majority of outages or assisting to avoid that majority of outages; fair?

A. Yes. It backs up not just generation outages but transmission and distribution outages.

Q. Mr. Koppe, I have some questions for

you. Could you tell us what your terms of reference were for the work you have done here.

MR. KOPPE: A. I don't think I understand the question.

Q. What did your client ask you to do?

MR. R. WATSON: Sir, I would suggest that Mr. Koppe only deal with that in very general terms. We certainly don't want to get into discussions between a solicitor and his client and instructions to experts.

MR. KOPPE: Over the last year and a half, I have been generally reviewing Hydro's presentations and the presentations of other witnesses on subjects related to power plant costs and performance. And in this case specifically I was asked to prepare an evaluation of Hydro's life extension plans for Nanticoke and Lambton.

MR. D. POCH: Q. The balance of the interrogatories that have been filed B9.7.1 through 9.7.23, did you answer all those interrogatories or did the MEA or some other person working for the MEA answer any or all of those interrogatories?

MR. KOPPE: A. I answered them all.

Q. So I take it that you are content to adopt them here as your evidence?

A. Yes.

Q. I would like to refer you to 9.7.3 where we asked you, we cited your reference to the fact that you have done a series of detailed analyses of various facilities and we asked you if you considered your paper presented here as such a detailed analysis. You said no. So I have a few questions about what you did do and what you didn't and the applicability of your findings.

You suggest that putting scrubbers on Nanticoke and Lambton could turn out to be much more expensive than Hydro has suggested and that there might be more creative ways available to lower environmental impacts. Is that a fair characterization?

A. I don't think so. I don't think I said that the cost of putting scrubbers -- I don't think I disagreed with Hydro's estimate of the cost of putting scrubbers on Lambton and Nanticoke.

Q. I think then to be more precise you're concerned that the life extension costs may turn out to be more expensive than Hydro's assessment. Are you comfortable with that?

A. Yes, more expensive than this base case estimate of a few million dollars a year which as I say again Hydro is not claiming that that is their, is going to be their total expenses of continuing to

operate these units.

[11:20 a.m.]

Q. And specifically, with respect to scrubbers you say there may be more creative ways available to lower environmental impacts at a lesser cost. Have I got that right?

A. Yes. Those may not be available to Hydro, but they are available to society.

Q. I had a chance to look at your CV. I didn't really see what I took to be qualifications to comment on environmental regulation or strategies to obtain reductions in emissions. Have I missed something?

A. Perhaps. I don't consider myself an expert overall on environmental regulation or environmental damages. I have studied the cost of emissions controls on power plants quite extensively and I did do a fairly major study for New England Electric last year looking at costs of reducing emissions of criteria pollutants from a whole variety of industries.

Q. Okay. What research did you do to identify strategies specifically applicable to the Ontario situation for reducing emissions of sulphur dioxide and nitrogen oxide from the existing system

with and without scrubbers?

A. If we are limiting ourselves to the options on Hydro's existing systems all that I did was to review the various options that Hydro has set out, which is the CPMs, the SCRs, the low sulphur coal, and the scrubbers, and look at those costs.

Q. What research have you done on the possibility of cheaper reductions being possible within Ontario, reductions that are not otherwise to be pursued as part of other government regulatory initiatives?

A. The studies that I did for New England Electric?

Q. No, I am talking specific to Ontario.

A. Specific to Ontario? I have not looked specifically at Ontario. My studies have been for North America on the whole.

Q. Are you familiar with the details of the Countdown Acid Rain program and the regulations of the Ontario government?

A. In general, yes.

Q. You are aware that they cover more than Ontario Hydro?

A. Yes.

Q. All right. Are you familiar with the

review of Ontario Hydro's acid gas reduction plans that was done some time ago by the federal Standing Committee on Fisheries and Forestry?

A. I have looked at a couple of evaluations. I'm not sure if that was one of them or not.

Q. That was where, if I can paraphrase, they said: Relying on nuclear power instead of scrubbers was an unreliable strategy. Does that ring a bell?

A. I don't remember those words.

Q. All right. Do you have any familiarity with the division of powers between the federal and provincial government as it might impact on the practicality or capability to regulate emissions in different sectors in Ontario?

A. No, I do not.

Q. All right. Now, you have mentioned the tradable permit approach as an example of a preferable and from your perspective mitigation approach. Mr. Shepherd has already discussed it with you. Who would you imagine that Hydro would trade with?

A. That would depend on the pollutants we are talking about and the geographical scope of the

requirements. You have to be more specific.

Q. And you are not in a position to be more specific, not having studied the particular regulatory structure in Canada, I take it?

A. That's right.

Q. I think you agreed with Mr. Shepherd that tradable permits in and of themselves don't produce emissions reductions; they just more effectively allocate them. Fair?

A. That's right.

Q. And when I say "more effectively" that has to do with the price of the technology?

A. A system of tradable permits seems to be the most efficient way of achieving a given reduction in emissions for the lowest cost.

Q. So then, your comparison of the costs for forecast for the price at which these permits will trade at in the States, I think you may have already agreed to this, but that is going to -- in your comparison to what Hydro's marginal costs are, that is going to be reflective of both the difference in the degree of optimization or allocation of these cuts and the starting point, how much the government is rationing emissions.

A. Yes.

Q. All right. Now, I want to be very clear on this. You are not suggesting, are you, that this Board should adopt -- should say, well, if it is good enough for George Bush and Dan Quayle it is good enough for the people of Ontario?

A. I am not suggesting that, no.

Q. All right. And you do seem to suggest, if I hear you correctly, that the degree of rationing in the States is reflective of the Executive and Congress' view of what is worth doing to cut emissions; is that fair?

A. Yes.

Q. They understand what it costs to cut emissions and they have pushed only so far?

A. Yes.

Q. All right. And you, I take it, would agree that that is a very political decision?

A. In the sense that the level of control they adopted was almost certainly more stringent that could have been justified on the scientific evidence, yes.

Q. You are not an expert on the scientific evidence, are you?

A. No, I'm not.

Q. And you would agree that there are a

lot of factors that play in the States, some of which aren't in play here - for example, the coal lobby?

A. Yes. Well, I don't know. A coal lobby applies in the United States. I don't know if it applies here.

Q. Fair enough. Now, you expressed an opinion, if I can paraphrase you, that in line of your view of the relative responsibilities for deciding what is appropriate if a company wasn't regulated to reduce emissions then they shouldn't do so?

A. Yes, I think that's right.

Q. Can you advise us if that is your opinion or if that is both your opinion and your client's position?

A. That is my opinion. I have not discussed it with my client.

Q. Now, you indicated in I think it was page 6 of your testimony that Hydro had, you used the phrase, committed to expenditures of billions of dollars for scrubbers, FGD and SCR at Lambton and Nanticoke, and I think you have since noted that the situation may have changed.

I would like to refer to the documents that you did in -- I'm not sure if it was in chief or in answer earlier. These are the documents that were

before the Hydro Board. They are already before this Board in various other aspects of this Board's proceeding, but perhaps, Mr. Chairman, for purpose of identification we could mark these two exhibits at this time.

They are the memorandum or the materials attached to Mr. Campbell's letter of September 16th to Ms. Morrison, which includes amongst others the Senior Management Committee memorandum, dated September 16th, 1992.

THE REGISTRAR: That will be 788.

MR. D. POCH: And the other materials which had been in fact before this Board by way of an attach to an affidavit in support of an upcoming motion, but --

THE CHAIRMAN: Perhaps that should be filed separately.

MR. D. POCH: Perhaps we should separate the cover sheet, and the exhibit should solely be the memorandum to the board of directors, dated October 19th, 1992, the cover sheet being Capital Program Review.

THE CHAIRMAN: That will be 789?

THE REGISTRAR: Yes.

MR. D. POCH: We have stapled on it a

copy of my letter to Ms. Morrison, but that I think should be, for the purposes of today, for the record that not be included in the exhibit.

---EXHIBIT NO. 788: Senior Management Committee memorandum, dated September 16th, 1992.

---EXHIBIT NO. 789: Memorandum to the board of directors, dated October 19th, 1992.

MR. B. CAMPBELL: Mr. Chairman, just on this matter perhaps just to make life easier for everybody, on the October material that is material that Mr. Poch and I are in the course of discussing as to -- I am aware that it has been attached to the affidavit and we are discussing the mechanisms that might be appropriate to bring that before the Board in what shall I say is a more regular way, which I think I indicated to you a couple of days ago that Mr. Poch and I were discussing that matter.

As I say, if it makes life easier for everyone though Ontario Hydro does not dispute that the material attached to the affidavit is an accurate copy of the material that did go to Ontario Hydro's board of directors. We have now had an opportunity to confirm that. And for today's purposes I can at least go that far.

THE CHAIRMAN: Well, that is another

matter. We don't want to get into that any farther at this time.

MR. B. CAMPBELL: I don't intend to take it any farther. I just thought it might save some chaffing back and forth on that rather narrow point.

MR. D. POCH: That is helpful. At least my question can be not posed so much as a hypothetical then, and we can just take that as given for the purpose of my questions.

Q. Mr. Koppe, I am really just wanting to refer to the approach that apparently has been adopted by Hydro and then ask you for your opinion as to the adequacy of that approach now.

If we can start with Exhibit 788 I will give you all the cites that I have picked out just so we understand the chronology before I pose the question to you.

I noted on Exhibit 788 on the fourth page in the page enumerated 10 at the very bottom of the page --

THE CHAIRMAN: What page of what? I'm sorry.

MR. D. POCH: The fourth page - unfortunately, the pages aren't numbered - of Exhibit 788.

THE CHAIRMAN: Well, it starts with the memorandum and then it is the report of the Capital Planning Review and then Executive Summary?

MR. D. POCH: This is the second page of the Executive Summary.

THE CHAIRMAN: All right.

MR. D. POCH: Paragraph 10 is a discussion of deferrals of capital projects, and about two-thirds of the way down it says: as well as potential deferrals of some fossil emission control projects and reduced incentives for certain demand management projects, and I would just like you to note the comment:

> It should be noted that these preliminary proposals for deferrals are based primarily on economic evaluation. Additional analysis of environmental leadership, legal and hearing implications, and the impact of reduced momentum - that's with respect to demand management programs - will be required in the coming months.

And then, if you turn later in this exhibit there is a second document entitled Corporate Improvement Initiatives, and the pages are numbered

there, and if you look at page 14 of that sub-document, paragraph 3, about environment, it speaks of the capital expenditure forecasts for what I think we all agree are major investments, and it says:

> If these plants are not being used as extensively as initially anticipated there may be some flexibility to defer or modify these expenditures while still addressing environmental concerns.

Finally, if we go to Exhibit 789 if we just look at the second page, second sheet of the Executive Summary, item I, it says:

> ...deferring the decision on the fossil environmental control program to be used for planning purposes, pending the development over the next several months of an integrated strategy.

Now, Mr. Koppe, I think you have already said that you think Hydro is moving in the right directions if although perhaps for the wrong reasons in deferring a decision on this item.

I had taken it from your evidence that you would like to see some of the results from Hydro's life management program to provide some detailed information.

Do you think that the deferral of a decision to the point when a new integration is done, which I think is predicted as six months in these documents, is sufficient, or do you believe that information from the life management program should also be obtained, and if the latter, can that be done in that time frame?

MR. KOPPE: A. I believe that before Hydro spends substantial amounts of money on the existing plants, be that for environmental controls or for further rehabilitation or life extension, that they should have a complete evaluation, which would include the inputs from the life management program.

Q. To your knowledge, could we have inputs, sufficient inputs from the life management program? Will it have proceeded so far in the time frame that is being suggested here for this other information; that is, I think we all understand it has to do with the evaluation of Bruce "A", for example, and it is foreseen as about six months?

A. With respect to the life management program for the nuclear plants I have not looked at that.

Q. No, I am referring to the fossil plants.

A. With respect to the life management of programs for the fossil plants I have not seen any detail on where Hydro is right now and what they could do over the next six months.

As I understand what I have seen from them, the plan is to develop this information over the next couple of years. But depending on where they are they might be able to accelerate that, and I don't know.

Q. Your clear preference is for that information to be available if it is at all possible before an irrevocable decision is made?

A. Before they spend money, yes.

Q. Now, I didn't notice any reference to a year when Hydro would have to actually commit to rehabilitating Nanticoke and Lambton in your evidence. Perhaps that was because of the time you were working on it you had assumed they had already committed.

But when based on your understanding now would Hydro have to irrevocably commit to the life extension and emissions control equipment on Nanticoke and Lambton or choose this other path you say may be more economic?

A. Well, I think that is part of the problem with this whole issue, is that in a sense there

is no time when one either decides or doesn't decide.

Expenditures are needed at different times. The more money that is spent up to a given point, the less remains to be spent, the more one tends to be committed to continuing to use the plant. But there is no -- there is not ever a single threshold.

Q. I notice from various interrogatory answers that you examined the fossil managed surplus scenario using assumptions in the Plan Update, and in particular I saw that at 9.7.8.

Did you examine any other of the Update plans, or did your analysis come from facts filed in support of that particular one?

A. As I recall, I looked at two sets of LMSTM runs. Mr. Logan maybe can help me with this. One of them I believe was the fossil managed surplus and one I believe was something called an "upper" or something like that?

DR. LOGAN: A. Yes. The other one was the Update, upper case.

Q. All right. In 9.7.14 we asked you to describe the sensitivities that would need to be examined to determine whether or not rehabilitation of Nanticoke and Lambton was cost-effective, and I see in your answer to 9.7.14 you list a number of

considerations.

Am I correct that you did not do a full analysis and sensitivity analysis of these factors? The timing -- let's just take them one at a time so we can be sure. The timing of the rehabilitation expenditures?

MR. KOPPE: A. No, I did not.

Q. Or the amount and timing of expenditures for environmental controls?

A. No, I did not.

Q. Or the remaining life, performance of the station during the remaining life in the absence of rehabilitation and environmental expenditures?

A. Also no.

Q. The lifetime of the unit, performance of the unit during that lifetime?

A. Yes. They are all "no". I looked at Hydro's evaluation and saw that under some, what I thought were plausible assumptions, life extension of some of these units was marginal or even somewhat uneconomic, and at that point I said we need a good evaluation here. I don't have the data to do a good evaluation, and I stopped.

Q. You draw some comparisons between new station costs and the costs that Hydro suggested or you

suggest are more likely for life extended and scrubbed versions of the existing stations in Hydro's units.

Do you select costs for new station designs which produce the same environmental performance, or do you assume that the cuts in emissions can be had cheaper elsewhere in the economy?
[11:40 a.m.]

A. The alternatives that Hydro used in their evaluation and the ones that I'm talking about are the proposed new coal unit -- or the ones I am talking about are a proposed new 4 by 800 megawatt coal station, and the emissions from such a station would be very similar to the emissions from Nanticoke or Lambton after the FGD SCR and precipitator upgrades that Hydro is talking about.

Q. But in that scenario then you would be causing Hydro to expend the money for that technology in the new plant scenario rather than going the route you have earlier suggested of finding cheaper places in the economy to make those cuts; fair?

A. If they put those controls on the new plant, that would be true. I wasn't suggesting that they put them on.

Q. All right. There are a number of other items that might come into this comparison. For

example, I think we have already referred to the emissions regulation situation. That might affect the choice; fair?

A. I'm sorry, could you repeat that.

Q. The regulatory limits, the nature of regulation in Ontario might constrain Hydro's choice in this selection as between existing and new.

A. It might well.

Q. Would it matter if there were many new generating stations that were being added to the system, might this affect the replacement power costs or the load factor of the coal units?

A. Yes.

Q. Now, could you turn to 9.7.8. We asked you about what consideration you had given to some of these factors, in particular this possibility of other new stations being added to the system within our without Hydro's controlling. Specifically, we asked you about proposals that are being considered by MEA members in a number of locations.

The indication you have given us is that you just didn't examine those but you would agree that's relevant for the reasons we have just spoken of?

A. Yes, a complete evaluation needs a good estimate of replacement power costs and you have

to consider all these things to make that estimate.

Q. So, this would be another factor that would -- it would be good to have some closure on before Hydro made any irrevocable decision on committing to new fossil as opposed to significant investments in its existing system?

A. Well, I don't know that you ever get closure on some of these issues. When the time comes to make a decision you get the best information you can at the time and you decide.

Q. You would like there to be a reasonably good level of certainty though?

A. I would like there to be the best estimate you could make at the time. You can't get more certainty than there is. You just should understand things as best you can when you have to decide.

Q. You are not aware of any forecast by your client of what we can expect from self-generation of its members, are you?

A. I'm not aware of such a thing.

Q. Neither am I.

You also state in that answer that you did not examine demand forecasts. I take it you would agree that the load forecast is going to have an effect

on this question of whether to rehabilitate or the timing of rehabilitation?

A. In that it too affects replacement power costs, yes.

Q. And it affects the duty cycle of load factor on these plants?

A. Yes. I view that as part of replacement power costs but yes.

Q. I take it that, for example, your reference on page 3 of your evidence where you suggest new supply will be needed around 2009 or 10 to meet either or both of the increase in demand and the retirement of existing facilities, we have to take that comment with a caveat that you haven't examined the load forecast?

A. That is correct. That was based on the LMSTM runs that I specified.

Q. And are you aware that there is a likelihood of -- we are told there is a likelihood of further changes to the load forecast? I guess that wouldn't surprise you when we put it that way.

A. I saw words to that effect in this recent Hydro document.

Q. All right.

Would the availability of more low cost

demand management or load displacing NUG than Hydro has forecast have an impact on this question? Did you consider that?

A. No. I did what I said I did. I evaluated the economics of life extension in comparison with building a new unit and found that it was marginal and stopped.

Q. But you would agree that that comparison in fact can be affected by any number of these factors such as the competing resources, the cost-effectiveness of the competing resources, that is third resources, that might be selected in preference to either of those two or might affect the loading of those stations.

A. The comparison between life extension of a Lambton or a Nanticoke and a new station only depends on the expected capacity factor. With the expected capacity factor and whether a new station is the most economical alternative to life extension depend on all these other factors but I did not consider that.

Q. I take it then you didn't look at fuel price forecasts either?

A. Again for the same reason.

Q. Now, you have acknowledged, I think I

just heard you acknowledge, that the load factor on coal stations is an important variable in the analysis?

A. Yes.

Q. What about the performance of existing nuclear stations? For example, if the performance of the nuclear stations continues to decline, Hydro's assumptions for the need of intermediate load fossil plants might be drastically underestimated; fair? If you accept my premise?

A. I don't accept your premise. But if your premise is true, the conclusion follows.

Q. All right. I would like you to look with me at another document which I would like to put before you.

Mr. Chairman, this is a single page reproduced from Nucleonics Week, the same august journal that my friend from AECL referred to I think just two days ago. This is from September 3, 1992 and it is just a report on first half performance for '92 of Hydro's nuclear generation and the impact on Hydro's fossil plants. Perhaps that should be given a number.

THE REGISTRAR: 790.

---EXHIBIT NO. 790: Single page extract from Nucleonics Week, dated September 3, 1992.

MR. D. POCH: Q. Mr. Koppe, you will

note there that it says:

Hydro's nuclear generation for the first half of '92 fell 15 per cent from the same period in '91 and forced a huge jump in fossil-fired output. The fossil plants generated 30 per cent more electricity in the first six months of '92 than in the '91 period.

I take it you were unaware of that?

MR. KOPPE: A. I read Nucleonics Week every week so I presume I was aware of it. It is not something that I would have specifically recalled if you had asked me prior to seeing this.

Q. I take it that's not anything that you took account of in your study?

A. I didn't and I wouldn't have had I known it. Short-term variations in the performance of all power plants take place. You need to look at long-term trends to have any idea of what to project for the future.

Q. You have mentioned you have done such studies in the past but I take it you haven't done a detailed study of long-term trends of Hydro's reactors?

A. That is true. All the studies I have done have been for fossil plants in general and for

nuclear plants in the United States.

Q. When you crunch your numbers, you say you have taken Hydro's numbers, so I take it then that you have used numbers that presume a 24 per cent reserve margin rather than Mr. Logan's 21 per cent?

A. There is something strange going on here. The only purpose to which I put those LMSTM results was simply, was the statement as to roughly when Hydro was projecting that new capacity would be needed.

The comparison of life extension of Lambton and Nanticoke with the alternative of building a new plant was done over a range of capacity factors and didn't implicitly or explicitly make use of any LMSTM output or any assumptions on all these subjects we have been talking about.

Q. Well, Mr. Koppe, certainly at least in terms of the date when you need new capacity, reserve margin would affect that; right?

A. Yes.

Q. And Hydro at present -- did you want to add something?

A. Well, Mr. Logan was pointing out to me - perhaps he is the better one to say it - that in his opinion the change in reserve margin would change

the timing of need for new capacity by roughly a year.

Q. Hydro doesn't in fact maintain 24 per cent of its capacity in the form of CTUs at present, does it?

A. I don't know but I don't think so.

Q. Mr. Logan, can you confirm that?

DR. LOGAN: A. I don't have the numbers in front of me but they have several resources that could provide the reserve margin. CTUs, however, are the marginal resource for reserve capacity.

Q. Well, gentlemen, you would agree that a plant with -- an existing plant may well, it may well be appropriate to keep an existing plant on line longer if you want to use it for reserve capacity; you are simply not going to run it very much. That might be an option the utility would consider as a plant began to deteriorate? Use it less and keep it because there are so many sunk costs keep it for reserve rather than build a CTU?

A. That's correct.

Q. Just a point of clarification, Mr. Koppe. In 9.7.19 we asked you to clarify the various cost figures you incurred in your analysis. And in answer to the interrogatory you don't confirm what dollars were used; you simply indicate Hydro didn't say

so you assumed $91. Have you been able to check since?

MR. KOPPE: A. I have not checked since.

Q. What are your performance assumptions regarding the average capacity factors for Nanticoke and Lambton? Did you use the assumptions I think you spoke of earlier that Hydro has offered? I'm talking about the capacity factors.

A. Yes. Again remembering that what I was trying to do was simply find out if the economics of life extension on Lambton and Nanticoke were close enough that a more detailed evaluation would be necessary.

The specific value of the capacity factor was not important and I simply looked at the 40 to 60 per cent range that Hydro had assumed and that was what they were projecting as the capacity factor for Lambton and Nanticoke at the time.

Q. I understand. And we could characterize that as an intermediate loading?

A. That's in the intermediate to base load range.

Q. All right. And the more you are into a base load situation, you have fewer stops and starts, which are a wear and tear and an OM&A factor for these units. Is that fair?

A. In that range of capacity factors that is usually the case. It's not inevitable.

Q. All right.

And obviously the LUEC changes, depending if you on more of a base load versus an intermediate role, if you have got more kilowatthours to spread your fixed costs over.

A. It changes with capacity factor however that comes about.

Q. So you would agree if we want to compare costs we have to be very careful to compare costs using a similar load factor?

A. Yes.

Q. Page 28 of your evidence is Exhibit 743. This is the third bullet point. You cite a Hydro comparison, and I think you adopt it, between Hydro's OM&A costs and the average electric utility cost group, EUCG numbers; correct?

A. Yes.

Q. Could you turn up 9.7.22. A minute ago you agreed with me you adopted the Hydro 40 to 60 per cent loading. Do you see how you acknowledge that the EUCG numbers have a 58 to 60 per cent average?

A. I'm not sure you quite said it right, but the North American average for coal plants is in

the 58 to 60 per cent range and I presume that's typical of the EUCG units?

Q. Right. But that's not the average that Hydro is assuming? They are assuming, if we assume it's evenly distributed about a 50 per cent load?

A. I'm not sure that that's true and I'm not sure it's relevant. Let me try a couple of pieces of that. For future performance of Lambton and Nanticoke, I believe Hydro's projections were more in the range of 40 per cent. That's one point.

For the comparison of Lambton and Nanticoke, life extension with new plants, they looked at a range all the way from 20 to 60 and I focussed on 40 to 60. But none of that is relevant to the comparison with the EUCGs since here we are comparing Hydro's historical costs and it's the actual capacity factors of those units in those years that matters. In fact Hydro's capacity factors in 1990 were low and that is part of the reason why their costs appear so much higher than average.

In fact, I think if one were to do a more thorough and fair comparison of Hydro with the North American averages they do appear to be on the high side but not by as much as 70 per cent.

Q. Don't get me wrong, sir. I'm not advocating that Hydro is one of the more efficient utilities. That's not necessarily our position.

But it seems to me you have made the observation that they have OM&A costs well above the EUCG average, and your expectation was that because of economies of scale they would be 10 to 20 per cent lower than the average.

You have just acknowledged that they have a very different load factor on those plants, at least historically, which is the data you are comparing and Hydro compared, so it's not really a fair comparison, is it?

A. I think that's what I just said. When I wrote this I took that comparison at face value and afterwards I realized the things we have just been talking about and looked at it more closely; and when I did that, I concluded that Hydro is on the high side but not by that much.

Q. You have identified that a better analysis is certainly warranted before a decision is made. You have focussed on how this better analysis will be helpful to determining the trade-off between life extension and new fossil plants. Would you agree that that analysis and the costs that it would disclose

would also be very helpful or would shed light on a number of other trade-offs for example between coal options and refurbishing nuclear plants to the extent that turns on a costs consideration?

A. I think your question is should one do the same kinds of analyses for those issues, and I think the answer is yes.

Q. All right. And the analysis, indeed a number of the facts that you would like to see uncovered for coal costs and life extension costs and so on would, in fact, be the same facts, a subset of the facts that you would need to make those other comparisons, and they would be helpful in that regard.

A. The same kinds of facts would be helpful.

Q. Indeed if we are comparing coal and nuclear, some of them may be the same, very same facts, although obviously you need the other half of the equation too.

I'm just saying some of the facts which you have identified as some of the gap you have identified here is not just a gap for this determination, for this trade-off; that's going to be information, that same information that will form part of the information we need for other decisions such as

potentially a trade-off between coal and nuclear.

[12:00 p.m.]

A. Yes, I don't think I am disagreeing strongly with you. I am just a little worried about whether the way -- the exact way you are wording that seems to be saying that some of these facts about the coal plants would influence the decision on the nuclear plants, and that is a--

Q. Cost projections?

A. --tenuous connection, but I think the important thing is you would want the same kinds of facts for the nuclear plants to do the evaluation for nuclear plants.

Q. Well, if there was a competition at the margin between differing resources and coal and that competition turns in part on costs, then obviously better cost information about coal is important; you would agree with that?

A. Yes, that's correct.

Q. That is true between coal and gas or coal and conservation. So this is an important gap?

A. Yes. Again, I don't want to draw too fine a line, but only to the extent it determines whether the coal plants will be life extended.

Once the decision is made on whether or

not to life extend the coal plants then the specifics of the coal plant costs do not affect the decision on the nuclear plant.

So you don't necessarily need to resolve all of these coal costs to evaluate the nuclear plants. You only need to resolve them to the extent you know whether you are going to life extend Lambton and Nanticoke or not.

Q. But what if the competing options are to rely on further coal at all as opposed to rely on one of these other fuels or conservation?

You wouldn't decide to life extend or not before you saw that you laid out all your options; is that fair? You want to do integrated resource planning?

A. That's true.

Q. All right. Now, you specifically highlight your skepticism about the life extension cost estimates for Lambton. Do you know which estimates Hydro has used in its avoided costs - the base case or the high?

A. Are we talking about the estimates of the long-term costs associated with life extension, not the current rehabilitation costs?

Q. Correct.

A. The answer is, I don't know. I don't know that.

Q. You would agree with me that to the extent that Hydro may have underestimated these costs and included that same underestimation in its avoided cost they may then be placing an inappropriate low value on alternative resources; that is, their avoided cost maybe too low so they may be underrelying on other options which they are measuring against avoided cost?

MR. R. WATSON: Sir, Mr. Koppe is here as an expert on life extension. He is not here as an expert on avoided cost.

MR. KOPPE: I think that is what I was about to say. It sounds plausible, but I don't know if I am familiar enough with avoided cost evaluations to know for certain that that is true.

MR. D. POCH: Thank you. Those are all my questions. Thank you, Mr. Chairman.

THE CHAIRMAN: Thank you, Mr. Poch. Is there anyone else before Mr. Campbell? Mr. Greenspoon?

MR. GREENSPOON: Thank you, Mr. Chairman.

<u>CROSS-EXAMINATION BY MR. GREENSPOON</u>:

Q. Dr. Logan, I represent Northwatch, which is a coalition of environmental groups from Northern Ontario.

I wanted to talk to you just briefly, as you may have gathered from the interrogatories that I asked, about the impact of the reserve margin or the impact upon the reserve margin of the grid, the transmission system, and regional generation, small scale generation.

First, let me ask you about your opinion of the main need for a reserve margin without getting into too much detail. What is your opinion of that?

DR. LOGAN: A. The purpose of the reserve margin is to cover random outages of generating units and to cover demand forecast uncertainty and other uncertainties that may affect the ability of the utility to meet demand.

Q. All right. And you say in your paper that when you talk about -- on line 16 or line 20 of page 2, you talk about the primary effect of a reduction, when you are talking about the impact of your thesis that it can be reduced, and you are asked about the effect, you say:

> The primary effect of a reduction in reserve margin is to reduce the total amount of capacity additions required in the resource plan, and this reduction occurs primarily in the amount of new

peaking capacity required.

So in response to the answer you gave about the main need for reserve, is it also a corollary of that that reserve mostly or at least to a large extent relates to peaking capacity?

A. Primarily. You can construct scenarios under which the timing of a base load addition might be affected too, but it is primarily a peaking capacity thing.

Q. Okay. And just one further thing just generally to put this in perspective. The lower your reserve, the cheaper you run the system. Is that too simple or is that fair?

A. Holding all other things equal, if you reduced your reserve capacity by not building some resources, gas turbines, then you would reduce the capital and operating costs of the system.

Q. So it would be fair to say --

A. The capital costs of the system.

Q. So all of us here would like to have as low a reserve as possible: Hydro, you, all of us? That is in all our interests?

A. We would like to have the economically optimal level of reserve margin.

Q. All right. Now, just getting

specific for a minute about the system, are you aware of the system that we have in Ontario; that is, the transmission system? Have you looked at it?

A. To some extent.

Q. To some extent. All right. The links between the northeast region and the northwest region, does that mean anything to you?

A. That phrase doesn't mean anything in particular to me.

Q. The interconnection between the -- do you know what the northeast system is and the northwest system?

A. I'm not sure I know what the northeast system is. I understand the northwest system to mean the resources and the loads that are going up towards Manitoba.

MR. R. WATSON: Mr. Chairman, I think we are confusing two concepts. I believe there are two systems in five regions. There is a northeast region and a northwest region. Perhaps we should ensure we have our terminology --

MR. GREENSPOON: Q. Northeast region and northwest region, yes.

DR. LOGAN: A. What does the northwest region cover? Maybe I shouldn't be answering questions

on things I don't know about.

Q. No, that's fine. It sounds like I shouldn't be asking any questions about this.

MR. R. WATSON: Mr. Chairman, I think Dr. Logan has just identified the issue. He's here to talk about the reliability and reserve margin, not transmission.

MR. GREENSPOON: Q. Is it your position that there is no connection between reliability and reserve margin and transmission?

DR. LOGAN: A. No, that is not my position. You need to account for the reliability of your transmission links between generation and the load centre. I am not an expert though on transmission between sub-areas or different load centres within Ontario.

Q. Okay. Now, let's put a hypothetical on the table here.

What I want to do is compare twenty-five 1,000 megawatt units, okay, which is similar to what we have in a broad, broad brush in Ontario. Would you agree with that?

A. Ontario has about in the neighbourhood of 20,000 megawatts of demand, give or take a couple of thousand.

Q. Yes.

A. However, Ontario's resources are not as simple as twenty-five 1,000 megawatt resources.

Q. Okay. I want to compare absolutes, and I realize that we are somewhere -- we are less than that. But let's just say for this hypothetical.

A. You are posing a polar situation?

Q. I want to pose a polar situation.

A. Beyond the current situation.

Q. That's right. You got it. So twenty-five 1,000 megawatt units, we have got 25 of those, and as a result it would be fair to say that you would argue that we need a reserve capacity for something like that where we have large units of about 20 per cent all other things being equal?

A. Well, my 20 per cent recommendation is based on the current system rather than this hypothetical system.

Q. All right. Well, let's get to the other system then that I am proposing, and maybe you can tell me what the difference will be in the reserve because that is what I want to know.

You have got twenty-five 1,000 megawatt units or you have twenty-five 10 megawatt units.

A. 25...?

Q. 2,500 ten. Which needs the higher reserve?

A. It may be that the system with the smaller number of large units will require a higher reserve, but I don't know if that will be by a large amount. I would need to look at a probabilistic calculation to judge whether the difference in reserve margin is significant.

If you are comparing five of the large units against 500 of the small units, then the difference is more obvious, but when you get as many as 25 of the larger units, 25 is becoming a smaller portion of the total demand of the system, so the difference becomes less obvious.

Q. Well, let's add another variable then.

Let's say that the 25 are not as close to the load generally as the 2,500. In other words, let's take the 2,500 and spread them out over the province so they are close to load so you have got supply near load, and let's take the 25 and say that they are located not necessarily close to the load. They are located based on other strategies.

Again, wouldn't that mean a higher reserve margin for those 25 than for the 2,500?

A. It could, but that depends on the assumption that the size of the units is small compared to the load within their areas because you need the units to be small enough that you have the small unit effect within the area that you are serving.

Either that or you need to assume that the transmission interconnections between the sub-areas are sufficiently strong that units in one sub-area can backup outages of units in other areas.

Q. But if you have 2,500 matched units, 2,500 units that match the load in every area, so obviously we would have more units in a bigger load area than in a smaller load area, all of these factors start to add up, that you have a more reliable system when you have more units of smaller capacity?

A. Again, that depends on the comparison of the size of the units to the load in the sub-areas and to the transmission interconnections between the sub-areas.

Q. Just one last point on that issue then is if, as you said earlier, we can match reserve to peak or there is a connection between reserve and peak, presumably -- I think my understanding is the peak is early morning in the winter in Ontario, is that your understanding - when everybody's got their

toasters on and their hot water, they are having showers, it is dark?

A. I haven't looked at Ontario's daily load profile recently. I would guess that it is in the morning, but I don't know how early it is.

Q. Let's approach it another way. The peak in Ontario is probably when everybody is using a fair amount of electricity. It is going to be spread out. It is going to be a province-wide phenomenon; is that fair?

A. Maybe -- well, it depends upon how much diversity there is between the different areas. I would guess that in urban areas that the peak occurs when people go to work and plug in their coffee pots the first time in the morning.

Q. Well, whenever it is it is at a time when a number -- a lot of users are--

A. A lot of people are using electricity.

Q. --using electricity. Mr. Campbell says he thinks it is at night. That is maybe what the exhibit shows, but in any case --

MR. B. CAMPBELL: I hate to confuse things with an exhibit.

DR. LOGAN: It could be at night, too,

when people first go on and fire up their stoves and get ready for supper.

MR. GREENSPOON: Q. Okay. Whenever it is there is a point when a lot of users are using electricity?

DR. LOGAN: A. Yes.

Q. If we had a system in Ontario where we had small cogeneration where a lot of users could avoid this peak, for example something like we have in the hospital in London or in Ottawa, where a university or an apartment building has a gas-fired cogenerator that is also producing electricity, the need for the reserve capacity is going to drop. If you can drop the peak you are going to drop the reserve capacity?

A. Well, the cogeneration is generation, and you would still have the demand for electricity unless you are accounting for that cogeneration on the other side of the meter or something.

Q. All right. But you would agree with the principle that if a consumer can reduce his consumption at the peak that is going to have an impact, and if a lot of consumers reduce their consumption, say they are generating their own electricity at the peak, that is going to impact on the reserve?

A. Yes, if customers have their own generation then the utility needs to have less generation.

Q. Right. Okay. Is that not -- all right. I will just leave it at that. I was going to ask you about the northwest, but maybe I will ask Mr. Koppe about the fossil plants.

Did you look at ones in the northwest or did your analysis separate the plants?

MR. KOPPE: A. No, I focussed on--

Q. The life extended?

A. --the life extended units which are Lakeview -- or, I'm sorry, Lambton and Nanticoke.

Q. I think my friend Mr. Poch asked you whether your client's position on better standards by Ontario Hydro was your client's position or whether that was your position. You indicated...

In other words, if Ontario Hydro wants to better the provincial regulations in your opinion they shouldn't. That is your position, not your client's position?

MR. R. WATSON: That question has already been answered, Mr. Chairman.

MR. GREENSPOON: Q. You are aware that Ontario Hydro is a Crown Corporation, Mr. Koppe?

MR. KOPPE: A. Yes.

Q. You know that that means that they are owned by the people of the province of Ontario?

A. I don't know that, but I certainly will accept it.

Q. Did you know that Atikokan and Thunder Bay, the two fossil plants in the northwest, are not destined to have scrubbers put on them?

A. Yes, I did know that.

Q. You did know that. And I understand Ontario Hydro bases that on economics.

A. I haven't seen an evaluation of that. I believe they are burning very low sulphur coal, which would make scrubbers particularly uneconomic.

Q. I'm not sure that that is true, that they are burning low sulphur coal, but in any case they are not going to put scrubbers on them.

I just wanted to ask you, if we get into a system that you advocate of trading regulatory quotas or however you want to determine that, that would be a further barrier to Ontario Hydro putting scrubbers at Atikokan and Thunder Bay; is that not true?

A. I don't know.

Q. Well, wouldn't that make sense? If Ontario Hydro had a quota for sulphur dioxide and they

had done all they could and let's say the regulations drop next year, let's say they can only put out half of what they do, or in 2000, if Hydro could trade away that extra half that they had to reduce they might be better -- it might be cheaper for them to do that than to put scrubbers on Atikokan and Thunder Bay?

[12:20 p.m.]

THE CHAIRMAN: Well, that question is getting pretty remote and really is argumentative. I think the witness' position on this is -- at least I understand what it is.

MR. GREENSPOON: All right.

Q. I will just ask one other question then and that is: Is it the MEA's position that trading of quotas -- is that a position that the MEA advocates or is that a position that you advocate.

THE CHAIRMAN: I'm not sure he has to answer that question.

MR. GREENSPOON: All right. Those are all the questions I have.

THE CHAIRMAN: Mr. Campbell, I don't know. We are seven minutes away from the luncheon break. Should we start this after lunch?

MR. B. CAMPBELL: The last time I had a discussion at this time of day about an adjournment I

made a serious error, so I'm not even going to touch the topic. I would be content to go for seven minutes or start after lunch.

THE CHAIRMAN: Let's adjourn and come back at a quarter to two.

THE REGISTRAR: Please come to order. This hearing will adjourn until 1:45.

---Luncheon recess at 12:23 p.m.

---On resuming at 1:45 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Be seated, please.

THE CHAIRMAN: Mr. Campbell.

MR. B. CAMPBELL: Thank you, Mr. Chairman.

CROSS-EXAMINATION BY MR. B. CAMPBELL:

Q. Mr. Koppe, I would like to start with you, please, and I guess get your agreement to the simple proposition that in considering the capability of the existing system one does need to assume a service life for the major capital facilities -- for the major generation facilities?

MR. KOPPE: A. I would agree to that.

Q. Hopefully it won't be the last time this afternoon but we'll start with that.

And as I understand your evidence with

respect to fossil facilities, fossil generation generally, in your opinion and experience they can be economically life extended beyond 40 years as a general rule?

A. Yes, that's correct.

Q. As I understand it, your argument with Ontario Hydro is that you say there has not been sufficient analysis to commit the work required to life extend these stations? To put it in your terms: that is to actually get out there and start spending the money?

A. Yes, that is true.

Q. I take it you would agree that there is a distinction between a decision to start spending a whole lot of money and a decision that is a -- or a difference between that kind of decision and an assumption for planning purposes that lives can be extended?

A. I think that would generally be true except to the extent that by assuming the lives of some units will be extended you do not start doing something else which will later result in reducing your options.

Q. All right. And you are aware, I take it, that the impact of the conclusion that some life extension should be included in the planning, in the

analysis that Hydro did for the Update, had the effect of very slightly advancing the in-service date for new facilities. That was the the effect that Hydro projected; it was not a major advance for new facilities? I take it you are aware of that?

A. Yes, I am.

Q. So that in responding to Mr. Shepherd's question earlier this afternoon as to what the Board should do if it had any doubts about the costs associated with this, one would want the Board presumably, I would ask you to agree, to take into account the impact on the planning decision as to the degree of advancement of new facilities that would be required with or without life extension?

A. That is true as far as it goes. I think in terms of short-term considerations the thing that concerns me more is that if it is not economical to life extend some of these units, it might be more economical to shut them down before 40 years, and that might advance the need for capacity.

But as long as we are only talking about future capacity, capacity in the 40-year-plus range then what you say would be true.

Q. And I take it that you are aware of Mr. Meehan's evidence on Panel 8 that although life

extension has been assumed for planning purposes; there is more than enough lead time to do detailed evaluations about the economics alternatives and other advantages and disadvantages of committing the funds to life extension? Are you aware of that evidence given by Mr. Meehan?

A. Yes.

Q. I take it you would generally agree that that is a wise thing to do before committing the funds?

A. I would agree with that, yes.

Q. All right.

DR. LOGAN: A. Let me add that analysis should not be postponed so long that you foreclose other opportunities.

Q. Nor did Mr. Meehan, you would agree, make any suggestion that it should.

A. That's correct.

Q. Thank you.

I want to turn then, Mr. Koppe, to the question of your reliance on economic considerations with respect to the addition of scrubbers or other acid gas control measures. You recall speaking to that this morning?

MR. KOPPE: A. Yes.

Q. Would you agree as a general proposition that with the proposition that Hydro has to balance environmental, cost, safety and reliability considerations when planning new facilities and cost or system need to meet regulatory limits may not be the primary consideration for some decisions?

A. In the broadest sense that's clearly true since some decisions don't involve environmental considerations but --

Q. But where all of these things are --

MR. R. WATSON: Mr. Chairman, I think Mr. Koppe still had something to add to his answer.

MR. B. CAMPBELL: Sorry.

MR. KOPPE: My feeling is that the government ought to set standards that weigh the benefits to society of reducing emissions against the costs and set regulations that apply to everybody and then everybody ought to comply.

If Hydro believes that it should go beyond that, then as a minimum it should present some analyses that indicate why that is in the public interest and I have not seen such analyses.

MR. B. CAMPBELL: Q. All right. Well, let me suggest to you one approach that would take you beyond existing regulations and see whether you would

temper your view in light of that.

Where it is quite clear to a corporation such as Ontario Hydro that customer and government expectations are that future environmental regulations, for instance, may well become more stringent in future years, given that we are engaged in a long-term planning exercise wouldn't it be fair to anticipate those kinds of things in making one's planning decisions?

A. That certainly should be part of one's contingency plan.

Q. And it may be that if the realistic assumption to make is in fact that regulations will be more stringent, then one should build into one's cost estimates, for instance, the cost of meeting those future anticipated regulations or expectations?

A. I don't think it's a question of building them in or not building them in. It's a question of looking at the alternative scenarios and trying to optimize present actions to minimize costs under a variety of possible outcomes.

Q. But the effect of looking at future regulations and the probability that they would be higher or more difficult or require greater control measures to achieve those future regulatory limits can

only surely have the effect of adding cost? It is unlikely, for instance, that acid gas regulations will be reduced?

A. I think that's true.

Q. So that when we are talking about making allowance for future anticipated regulatory limits, that is a cost element which goes beyond what is required to meet today's regulatory limits and you would say, I take it on the basis of what you have said previously, that that is appropriate to take into account in a planning decision?

A. Yes. But again the distinction I was making is that one doesn't plan on doing those things; one considers them in the range of contingencies.

Q. But eventually one has to make a decision and that particular contingency I thought you agreed from a cost perspective for instance can only add to cost?

A. Yes. I don't think we have said anything new here, yes.

Q. All right. And I take it that your view is that even if -- that it is inappropriate for a Corporation such as Ontario Hydro, even though it is in legal form a collective owned by its customers, or a co-operative I think would be the correct technical

term, a co-operative owned by its customers, even though that is the nature of the Corporation and even if Ontario Hydro became absolutely convinced that its customer owners desired the Corporation to go farther than strictly meeting the regulatory limit, you would say that's inappropriate?

A. No, I don't think at that point I would. If the customers indicate that they want to spend the money to reduce the emissions, then they should get what they want.

Q. So that to the extent that there is evidence before this Board that goes directly to that point and supports the proposition that Hydro's owner customers do in fact want more than is strictly required by regulatory limits, then you would modify your opinion?

A. That is true.

Q. Now I want to talk to you about a number of your cost comparisons and I think I would like you to start by asking you to get out Interrogatory B9.1.1.

THE CHAIRMAN: Are you going to be referring to a number of interrogatories?

MR. B. CAMPBELL: I think this is probably the only interrogatory I will be directly

referring to.

THE CHAIRMAN: We better give it a number then.

THE REGISTRAR: 781.12.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 781.12: Interrogatory No. B9.1.1.

MR. R. WATSON: Mr. Chairman, just to help out Mr. Koppe, I believe Mr. Campbell that's the interrogatory you asked of Mr. Koppe?

MR. B. CAMPBELL: Yes. I will provide him with a copy.

Q. Now, you will recognize this interrogatory and it has to do with one of the comparisons you made between Hydro's coal station costs and those in the Electric Power Research Institute's technical assessment guide, colloquially known as EPRI TAG. Are you familiar with this?

A. Yes.

Q. And you prepared this answer?

A. Yes.

Q. Now, the first thing I would ask you to note or ask you to confirm is that that this is your explanation of your assertion in your evidence that Hydro's estimates for coal stations are about 20 per cent higher than those in EPRI TAG?

A. That is correct.

Q. The first thing I would then ask you to confirm is that the correct comparison using EPRI TAG has to take into account various, has to take into account confidence limits which are set out in that document? I take it you are aware that that document sets out confidence limits associated with different kinds of estimates?

A. It does do that, yes.

Q. I would ask you to confirm that the kind of estimate that we are talking about here falls in the category under the design and cost estimate rating in EPRI TAG of preliminary and that the technology development rating is A, being a mature technology?

A. I'm certain that you are right on A, the preliminary sounds right, but I don't remember the classifications in TAG well enough to be absolutely certain.

Q. Well, I'm not anxious to add a whole lot to the paper but I can show you a copy just out of my notes and ask you just to confirm this. What I'm leading to is to ask you to confirm that the confidence limits associated with this kind of estimate that you have prepared are plus or minus 10 per cent for the

accuracy range in EPRI TAG.

I think that's the chart from EPRI TAG. I don't have copies. But what I'm referring to is the design and cost estimate rating and then the technology rating.

I would just ask you to confirm that based on the type of estimate that you are making the accuracy range for EPRI TAG for the calculation you have done is plus or minus 10 per cent?

A. Yes, that is correct.

Q. I'll never find this page again if I don't get it back, so thank you.

Now can you explain what that means then, the accuracy range being plus or minus 10 per cent?

A. I'm not sure of the precise definition that EPRI gives but in simple terms it means that if you actually went out and built one of these plants it might cost as much as 10 per or more or as little as 10 per cent less than what you estimated.

Q. Would it also be fair to say if in comparing estimates that comparison fell within the plus or minus 10 per cent range, you can't go any farther than that in concluding what the differences are? That's what the accuracy ranges -- that's the limit of the accuracy range plus or minus 10 per cent?

A. Could you ask that question again.

Q. If for instance you did a comparison of two plants and the number that you calculated was 4 per cent apart, to pick a number, based on preparing a preliminary estimate for a mature technology according to EPRI TAG you could not conclude that there was any significant cost difference between those two options?

[2:05 p.m.]

A. In a statistical sense that is true.

Q. But that is what the accuracy range is tended to convey to you?

A. Yes.

Q. Now, one proposition that I would like to put to you is whether you have given consideration to whether EPRI TAG may underestimate in any significant component the costs faced by Ontario Hydro as reflected in the options discussed in the Thermal Cost Review and the Update to the Thermal Cost Review?

A. I'm not aware of any of such differences.

Q. Do you have the Thermal Cost Review with you?

A. No, I don't.

Q. I'm going to give you a series of

figures that are taken - and we will get you a copy of the Thermal Cost Review; I'll have it in front of you shortly - taken from the Thermal Cost Review, which is Exhibit 35, Volume 2, and it is page -- well, it is section number... Mine cleverly does not have a page number on it. It is section No. 131.1, figure 131.1.

What this does is set out for a preliminary estimate what are called new site adjustments, and you would agree that the preparation costs or the costs associated with putting a station on a new site are appropriate costs to take into account?

A. Yes.

Q. Now, there is a list in that figure of a variety of new site adjustments for sites of the characteristics that have been assumed in the Thermal Cost Review, and they include, for instance, additional rock excavation of $21 million.

I take it you are aware that EPRI TAG in its assumption for a site has assumed a level site suitable for a pile foundation. You are aware of that, I take it?

A. Yes, I am.

Q. And so that this incremental cost of additional rock excavation would be applicable in Hydro's Thermal Cost Review cost but is not something

that is reflected in EPRI TAG?

A. Yes.

Q. Similarly, Ontario Hydro in its estimate has included a dock transfer facilities for $27 million. Again, I would ask you to confirm that no costs of that type were contemplated in EPRI TAG.

Now, can you confirm what I understand to be the case, that there is no allowance in EPRI TAG for dock transfer facilities of an amount of $27 million?

A. I am trying to recall whether that TAG estimate was of lakeside site or an inland site. Assuming that it was an inland site it would not have dock transfer facilities, but, of course, it would have equivalent rail facilities. You still have to get construction materials and later coal to the plants. So --

Q. Whatever the case may be, I take it you have not investigated that difference to determine whether it affects the outcome of the comparison?

A. I have not.

Q. Similarly, with respect to intake and discharge facilities, have you examined the assumptions in EPRI TAG as against what is in the Thermal Cost Review in order to assess the appropriateness of the comparison in that respect?

A. As I recall, the EPRI TAG estimate is based on a site with forced draft cooling towers, and I would expect those to cost more than the intake and discharge facilities for an open cycle cooling on a lake.

Q. Have you investigated, can you confirm one way or the other whether that is in fact the case using EPRI TAG estimates?

A. I do recall that the EPRI TAG estimates were based on forced draft cooling towers. That is as far as I went.

Q. Now, the next item is an adjustment downward in the Hydro cost, site location being assumed -- or labour rates being assumed for a site location that has lower labour rates.

Have you investigated that kind of labour rate consideration as between the two preliminary estimates?

A. The numbers that I produced in the answer to this interrogatory I adjusted to be typical of the EPRI TAG's labour rates for the northeastern United States since I did not have Ontario labour rates.

Q. So that there was no adjustment made for labour rates as used in the Thermal Cost Review and

the basis of those?

A. I don't recall what the basis for the labour rate adjustment in the Thermal Cost Review was. Perhaps you could point me to that.

Q. I am just asking you whether you did any such analysis or comparison, and I take it you did not?

A. Only by adjusting the TAG numbers to the northeast United States, which are the most expensive labour rates in the U.S.

Q. In terms of site location costs EPRI TAG includes a certain amount for site acquisition, as I understand it.

Are you aware of whether those figures are higher or lower than the site location costs shown in the Thermal Cost Review on this page, $30 million?

A. I do not recall.

Q. Now, the Ontario Hydro Thermal Cost Review also assumed that this site would be located in an area where accommodation would have to be provided for the labour force. There would have to be both a camp installation and camp operations, being two items of $44 million and $58 million, respectively.

You would agree, would you not, that those costs are not included in the EPRI TAG

comparison?

A. I believe that is true.

Q. The property purchase value -- I may have confused the site location expenses on my way through, but there are property purchase costs associated with the Thermal Cost Review of $17 million. Are you aware of what the equivalent figure is in EPRI TAG?

A. Again, I have seen the numbers, but I don't recall them.

Q. The final item is $4 million for site studies. Did you consider whether that was an appropriate figure in doing the comparison with EPRI TAG?

A. At the time I did this, which was about a year ago, I did look at that, but at this point I don't remember.

Q. Now, the total adjustments that Ontario Hydro has included in its estimates for this 4 by 800 station, as you can see here it totals up here to about $206 million. Do you see that total?

A. Yes.

Q. I am advised that when this basket of items is considered that this represents about 6 or 7 per cent of the costs on a new plant. That would be

consistent with your understanding of the figures?

A. I haven't done the arithmetic, but it is certainly in that range.

Q. I am also advised that looking at these basket of items EPRI TAG considers only a relatively small portion of them, being something in the order of $40 to $50 million, and the balance is all costs that are incremental in the Thermal Cost Review for Ontario Hydro's assumptions for a 4 by 800 megawatt station.

Is that consistent with your understanding of EPRI TAG?

A. Clearly, some of these costs are not in the EPRI TAG estimate, but as to whether your estimate of the number is correct or not I can't say from memory.

Q. Well, let's just assume as a hypothetical then for my purposes that 5 to 6 per cent of the total costs of the Hydro plant as a result of these baskets of items are costs that are additional to the EPRI TAG estimate. Then, to that extent, as I understand your evidence, you would have to reduce your differential between EPRI TAG and Ontario Hydro cost estimates by that 6 per cent.

A. If these were the only differences

that would be the case.

As I looked through this information a year or more ago I noted the existence of some of these differences, which tend to make the Hydro plant cost more. I also noted a few differences that tended to go the other way, the ones I recall being the fact that the plant in the EPRI TAG has the cooling towers, and the fact that the plant in the EPRI TAG has spare scrubber capacity. And both of those things are not included in the Hydro estimate. I did not try to weigh those in detail, but noting that there were offsetting things I didn't go any further than that.

Q. But when we asked you in the interrogatory for a comparison you have not provided us with any analysis of the detailed differences of that type between EPRI TAG and the Thermal Cost Review or the Thermal Cost Update estimates; is that correct?

A. There were no detailed analyses. It was a qualitative comparison at about the level I just described.

Q. Well, then, if a detailed comparison was done, for instance, on these items it showed a difference of -- I'll take you back again.

If it showed a difference in this basket of costs of 6 per cent incremental cost for the Ontario

Hydro facility I again ask you the question: Given what you must, I think, in the circumstances take as a hypothetical, given that, you would have to adjust your estimate downwards if you were dealing with that item?

A. If those were the only adjustments, if there were no offsetting adjustments that would be fair.

Q. But you are not able to say to this Board, not having done the analysis, what the result of that detailed kind of comparison would produce?

A. That is correct.

Q. Now, then I would like to turn you to the question of the formula used in EPRI TAG to adjust capital costs of a 4 by 500 megawatt unit to a 4 by 800 megawatt unit.

Perhaps I should expand slightly for the benefit of the Board and ask you to agree that in making the cost estimates what EPRI TAG does is produce a cost estimate for a 4 by 500 megawatt station and then use a formula, which you have cited in your interrogatory answer at page 7-6 of EPRI TAG, to scale up the costs from 500 megawatts to 800 megawatts; is that correct?

A. That is correct.

Q. Now, I am producing to you a page

from EPRI TAG, which I am going to ask you whether it in fact contains that scaled-up formula. If I could have the next exhibit number, Mr. Chairman?

THE CHAIRMAN: Next number, please?

THE REGISTRAR: 791.

---EXHIBIT NO. 791: One-page extract from EPRI TAG.

MR. B. CAMPBELL: Q. Now, the formula in the right-hand column with the number opposite in brackets (7-1) I take it is the formula that you have referred us to in your interrogatory answer; is that correct?

MR. KOPPE: A. Yes.

Q. Am I correct in my description of it that what it does is if one is working with a 500 megawatt estimate it is a formula for adjusting the capacity adjusting the costs up to an 800 megawatt station, for example?

A. Yes.

Q. And looking at that formula on the right column opposite 7-1, I think the formula is fairly straightforward. How does one correctly describe C with the little zero high and to the right? What do you call that?

A. I guess you would call it C super zero.

Q. Superscript zero? C(0) is the base unit cost, as I understand it, in dollars per kilowatt; is that correct?

A. Yes.

Q. And then the megawatt superscript zero is the base unit size in megawatts, which is 500 in your solution, in your interrogatory?

A. Mm-hmm.

Q. And the megawatts, the MW figure in the formula is simply the new unit size in megawatts, which is 800 according to your interrogatory?

A. Mm-hmm.

Q. What is the value for C(0)? Again, I believe it is in the interrogatory.

THE REGISTRAR: I'm sorry, what was that number?

MR. B. CAMPBELL: Sorry, I am asking for a dollar figure taken out of the --

THE REGISTRAR: I beg your pardon.

MR. B. CAMPBELL: Q. So it would be the 1264.6; would that be correct?

MR. KOPPE: A. Yes.

Q. All right. So C(0) is 1264.6, C is what we are solving for, which is the new unit cost in dollars per kilowatt; correct?

A. Mm-hmm.

Q. Then there is a factor A, and am I correct in my understanding? I am advised that if one is going from 500 to 800 the value A is set by EPRI TAG at .15?

A. That is correct.

Q. Now, in reviewing this interrogatory -- and I would ask you just to do the mathematics if you have got your calculator there, if it's easy to do.

My understanding is that in solving that equation you have used the value A equal to .3, which would only be appropriate if the unit size you were comparing with was being reduced. That isn't said in the interrogatory answer, but the mathematics that result, I am advised, only work if the .3 value is used for A.

A. It does appear that way, and if that is the case a mistake was made.

Q. I am further advised that that mistake, putting aside the site adjustment factors that we have talked about already, but that that mistake alone would reduce the differential in costs from the 20 per cent you used in your evidence to approximately 10.9 per cent. Can you confirm that number?

A. If you will give me a minute...

Well, I got 7 per cent, but I am not at all sure I did it correctly.

THE CHAIRMAN: I'm sorry, what did you get?

MR. KOPPE: I say, I got a 7 per cent change rather than the 9 per cent change that he got, but doing it this quickly I can't swear that I got it right.

[2:26 p.m.]

THE CHAIRMAN: Anyway it is quite a significant change in any event?

MR. KOPPE: Yes, it is.

MR. B. CAMPBELL: Q. In any event I would ask you this. I am advised that the resulting difference from that adjustment alone would reduce the differential to 10.9 per cent. Mathematics on the stand are always a chancy proposition and what I would like you to do is undertake that if you disagree with that would you please file a document explaining why.

MR. KOPPE: A. Certainly.

Q. I don't want a whole treatise. I just want it to address this very one mathematical correction.

A. I realize that the 7 per cent I was

calculating was the change in the estimate of the EPRI TAG. That's not the necessarily the differential.

Q. All right, yes.

But I understand it to be 10.9 per cent and perhaps if you consider that calculation, when you have had an opportunity, to be different, your counsel could let me know. Perhaps the easiest way rather than do an undertaking is that we will figure out how best to speak to it but I believe the right number to be 10.9 per cent. And unless Mr. Watson advises me differently we will proceed on that basis.

I then want to discuss with you -- well, just to finish that off. If for the purposes of this question you adjust, you accept that there are site correction factors that would reduce the differential by say 6 per cent off a 10.9 per cent base, the suggestion I would ask you to agree with is accepting that, then the cost differential between the two sets of estimates is now in the neighbourhood of 4 to 5 per cent and that is well within the range of accuracy defined for this type of estimate by the EPRI TAG document itself?

A. Given your hypothesis with which I have already disagreed, the conclusion would seem to follow.

Q. No. With which you have said you have done no analysis.

A. I have not done an analysis but I know that forced draft cooling towers and spare scrubber trains have significant costs and --

Q. And you have --

MR. R. WATSON: He hasn't finished the answer, Mr. Campbell.

MR. KOPPE: And whether they less than completely offset these other differences or more than offset them, I don't know, but I know that they are significant.

MR. B. CAMPBELL: Q. My simple point is you have not done the analysis?

MR. KOPPE: A. I have agreed to that at least twice before.

Q. Fine. Thank you.

THE CHAIRMAN: But even not having done the analysis for what it's worth he can disagree with the hypothesis. For what it's worth.

MR. B. CAMPBELL: Well, we will choose where to put our emphasis then. Thank you, Mr. Chairman.

Q. I want then to turn to the question of your cost estimates associated with scrubbers. Are

you generally familiar with the recommendations of EPRI and a similar kind of guidance they put out for scrubber costs?

MR. KOPPE: A. You mean something outside the EPRI TAG.

Q. Yes. Yes.

A. No, I'm not.

Q. I had thought reading your testimony that you relied on differences between EPRI costs and Ontario Hydro costs as supporting your proposition that Ontario costs were higher. Am I incorrect in that?

A. I cite a number of differences between Hydro costs and industry averages. In the case of construction costs for a new coal plant my comparison was based on the EPRI TAG. In the case of scrubbers it was based on a comparison with recently announced costs for 10 plants that are planning to add scrubbers. It was not based on EPRI numbers.

Q. If I could have a moment.

MR. R. WATSON: In fact, Mr. Chairman, those scrubber numbers are before you in the interrogatory filed by the Coalition this morning, Interrogatory 9.7.21.

MR. B. CAMPBELL: Q. My question to you, Mr. Koppe, is whether in making those comparisons, what

assumption was made with respect to chimney use in those assumptions. I will go right through to the bottom line of this which is that it is our understanding, I am advised, that costs of the nature that you are discussing do not include new chimney costs but the Ontario Hydro costs do include retrofitting a new wet stack to the Ontario Hydro facility in question.

Are you able to confirm at least the U.S. estimate side of it: that it does not in fact include new chimney costs, the costs of an additional new chimney?

MR. KOPPE: A. No, I'm not. These are estimated costs by the utilities for those 10 plants.

Q. And you do not --

A. I do not know which of those include chimney modifications and which do not.

Q. In fact you could not confirm one way or the other, as I understand it, whether new wet stacks are required or whether they are included in any respect? I take it you have not looked at it at that level of detail.

A. That is correct.

Q. It is fair to say, however, is it not, that to the extent that new wet stack costs are

not included in the U.S. estimates and are included in Ontario Hydro estimates, that would be a matter of some significant cost?

A. Yes, it would.

Q. Similarly, have you reviewed the U.S. cost estimates with respect to whether they include waste disposal facilities?

And again I will put to you what I have been advised and ask if you can confirm that, which is that with respect to scrubber operation, the cost estimates are consistent, the U.S. cost estimates are consistent with on-site storage or disposal, depending on which word you prefer, of scrubber wastes, whereas the Ontario Hydro costs assume more expensive off-site waste disposal facilities. Have you examined that kind of comparison?

A. No, I haven't.

Q. Again, would it be fair to say that those differences could result in significantly higher costs for Ontario Hydro?

A. That's certainly possible.

Q. Are you aware with respect to the U.S. cost estimates as to whether any provision has been made in those facilities for common services for additional scrubbers? And again let me tell you what

the Ontario Hydro evidence is on this matter, which is that Ontario Hydro has included in its cost estimates putting in place common facilities for four scrubbers but the cost of those common facilities has been entirely allocated to the first two scrubbers because these are committed in pairs but common services are put in place for all four.

Do you know whether a similar treatment has been taken in the States? And I would suggest to you that it likely has not given that we are more often taking about single or double unit plants?

A. I was about to say that. The plants we are talking about in the States are 1, 2, or 3, units on a site. But in all the cases I believe except Baldwin these are costs for scrubbers on all the units at a site. So, the common facilities are spread over those costs.

Q. Again that could make a significant difference to the cost comparison?

A. We know what that difference is because we know the costs for Lambton 3 and 4 scrubbers as well as 1 and 2.

Q. But that would be a matter that if one were to draw some conclusions, you would want to take that into account?

A. Yes.

Q. Now then I want to turn to your concern about Lakeview life extension costs. And I wondered whether you had had the opportunity to review the evidence of Mr. Burpee on Panel 8.

MR. R. WATSON: Mr. Campbell, you said Lakeview life extension. Do you mean Lambton?

MR. B. CAMPBELL: No, Lakeview rehabilitation costs, I'm sorry.

Q. Lakeview rehabilitation costs, which as I understand it, you have looked at Lakeview rehabilitation costs and you have used the information that you have gathered about those costs as part of the information that you rely on in raising a concern that Hydro has underestimated costs of life extension; is that fair?

MR. KOPPE: A. Yes, that is fair.

Q. All right. Now have you had the opportunity to review the evidence of Mr. Burpee on Panel 8 with respect to those Lakeview rehabilitation costs?

A. I have looked at so much material over the last year and half I don't -- I remember his name. I remember looking at Panel 8 evidence. Specifically what of his material I looked at, I cannot

recall.

Q. Let me try and paraphrase this and ask whether it is in your judgment a relevant consideration with respect to the consideration of Lakeview rehabilitation costs.

Mr. Burpee pointed out that in the early 80s it was forecast that four units at Lakeview would be -- I shouldn't use the number four.

It was forecast that the units at Lakeview would be mothballed by the late 80s due to reduced load forecast. Are you familiar with that?

A. I do recall that, yes.

Q. Mr. Burpee went on to say that staff was gradually cut back and maintenance reduced given that expectation.

A. Yes.

Q. And you have no reason to argue that with that?

A. I don't.

Q. He testified that known problems were simply not addressed in the maintenance problem. Do you have any reason to argue with that?

A. I do not.

Q. And he testified that subsequent to the decision to reduce maintenance because of the

potential for mothballing, energy production requirements at Lakeview actually increased but maintenance simply did not keep up. Do you have any reason to argue with that evidence?

A. No, I don't.

Q. He went on to say that by '86, it appeared that there might be a need for Lakeview beyond 2000 and rehabilitation then started to be considered. Do you have any reason to argue with that?

A. No.

Q. He then indicated in his testimony that a large portion of the final estimated rehabilitation cost represents the work that was not performed over the previous decade as a result of this set of circumstances that we have just gone through. Do you have any reason to think that Mr. Burpee was incorrect in making that statement?

A. No, I do not.

Q. What I would invite you to conclude from that, Mr. Koppe, is that if the station had been maintained as if it were to be a long-term going concern, if it had received those kinds of OM&A dollars over those years, rehabilitation costs could well have been substantially lower.

A. I think that is true.

Q. Thank you.

We talked a little earlier about contingencies and meeting environmental regulations, Mr. Koppe. I take it that you are aware that with respect to environmental regulation, Ontario Hydro is not entirely reliant on scrubbers; it is using lower sulphur coal in conjunction with flue gas conditioners. Are you aware of that?

A. Yes.

Q. It is using combustion process modifications at Nanticoke and they are planned for at Lambton as well?

A. Yes.

Q. And it is doing investigative work on urea injection for NOx reduction as opposed to the more expensive SCR technology?

A. Yes.

Q. These are, I take it, the kinds of alternatives that you agree Hydro is considering and ought to be considering in the course of its planning?

A. Many of those things have already been done but those are all things that reduce the emissions of SOx and NOx for costs per tonne that are far lower than the costs associated with scrubbers and SCR.

Q. And accordingly should be considered in the planning?

A. Yes.

Q. Do you have any reason to disagree with the evidence of Ontario Hydro that those matters are being considered in making these kinds of decisions when it comes to time to commit funds?

A. No. Again some of them have already been done and others are in the process of being done so they are clearly considered.

Q. Finally, I think you advised Mr. Poch this morning that you believed on perhaps sober reflection that the comments that you had made in your exhibit at page 28, lines 32 to 41, about Ontario Hydro's OM&A costs being higher - you used the figure 70 per cent - based on the EUCG comparison that you on reflection considered that comparison to be unfair. Do I have that correct?

A. I think so. The comparison was made by Hydro and the numbers are what they are. But I think that the unfairness comes about because there are differences between the way Hydro's units were operated in 1990 from the way typical plants are operated that explain part of that differential in cost.

Q. Is it not correct, Mr. Koppe, that

the figures that Hydro provided you in graphical form were in response to Interrogatory 2.9.12 and perhaps we could just add that to the number to the general number.

THE REGISTRAR: 781.11.

THE CHAIRMAN: Yes, that's the --

THE REGISTRAR: That's the one we had before.

THE CHAIRMAN: 781.12 that is your --

MR. B. CAMPBELL: Yes, if we could get the next number in that series, yes.

THE REGISTRAR: It will be 781.13.

---EXHIBIT NO. 781.13: Interrogatory No. 2.9.12.

MR. B. CAMPBELL: Well, that will be fine. 781.13.

Q. But is it not fair to say that the figures that Hydro provided you in graphic form in that interrogatory showed that up until 1988 Ontario Hydro's OM&A calculations showed that it was less than the EUCG average; in 1989 it's roughly equal to the EUCG average; and that the 1990 figure of 70 per cent, which you focus on in this section of your testimony, was in fact a 1-year number which you yourself pointed out in your oral testimony arises from some peculiar circumstances.

MR. KOPPE: A. Everything you have said is true up to the end there. The reason that initially I did not further question that 1990 number is that from other data from Hydro I had seen that in fact the absolute values of the cost, that is to say, the total amount of money spent per year at the fossil units including Lambton and Nanticoke had increased very substantially during the late 1980s and I assumed that that rise in the curve that Hydro had provided was due to that. In fact, it was partly due to that and partly due to the very low capacity factors of the fossil units in 1990.

Q. Is it not correct to say that the low capacity factors is by far the dominant influence?

A. No, I don't think that's fair to say.

Q. In any event it is correct to say that with respect to the years that you have referred to in your testimony, the only year in which that particular calculation, which is capacity factor dependent, results in a number higher than EUCG cost is in fact 1990?

A. The only historical year.

[2:45 p.m.]

But if you take Hydro's own projections of O&M costs for those stations for the future and

Hydro's projected capacity factors for those stations in the future Hydro is projecting those costs will be higher than the UCG averages in the future.

Q. And you have no reason to disagree with Hydro's projections of cost, as I understand it.

A. Not in that case.

Q. In terms of its future projections you accept the future projections of O&M costs; you have no reason to disagree with them?

A. That is correct.

Q. So that to the extent they are built into avoided costs or elsewhere in the planning, again you have no reason to disagree with those results?

This isn't a trick question, Mr. Koppe. I think it kind of flows from the last one, doesn't it?

A. It does, and I don't disagree with the projections per se. My only disagreement would be that given that the projected costs are higher than typical I might think Hydro could do some things to reduce them somewhat.

Q. I think they are trying to do just that. But my simple point is, there is no base on which, from what you have said, for instance, that one should adjust the costs which Hydro has used in its analysis to the extent that they are dependent on

fossil OM&A costs?

A. No, that's right. That is correct.

Q. Dr. Logan, if I could turn to you, please, I guess the first thing I want to do with you is what lawyers sometimes look little foolish doing but I will try it anyway, and that is basically to pick a nit.

If we could turn to your exhibit, please, which is Exhibit 742, towards the top of page 2 at about line 5 near paragraph 3 there you have been discussing your conclusions with respect to reserve margin, and you say: Another issue is that Hydro's method of solving for the optimal reserve margin is systematically biased in favour of a higher target reserve margin.

When I read that, the nit that I got excited about was systematically biased seemed to be applied in general application. As I have understood your paper and your evidence today that applies in particular terms. What you are talking about there rather is at page 13 the discussion with respect to CTU units, which runs from about line 16 to about line 32; is that correct?

DR. LOGAN: A. That is correct.

Q. So that one should put a little

marginal note -- if one is worried about the word "systematic" it would be quite fair to put a little marginal note next to that: See the comments on page 13?

A. That's exactly what that applies to.

Q. Thank you very much. Now, I want to give you a chart. It is a variation on a chart that everyone is probably thoroughly getting tired of, but I have just added a couple of lines that I will just take you through. And if I could have the next exhibit number, Mr. Chairman?

THE CHAIRMAN: Next exhibit number, please?

THE REGISTRAR: 792.

---EXHIBIT NO. 792: Extract from figure 2.1 of Exhibit 87.

MR. B. CAMPBELL: Q. As I say, I am sure everybody's getting more than a little tired of seeing this chart, but what I have done with this -- it is taken from figure 2.1 of Exhibit 87.

What I have done with this chart, which illustrates the effect of combining the cost of supply and the cost of customer interruptions into the total cost of electricity to the customer, is tried to demonstrate in a simplistic way the effect of reducing

the reserve margin from 24 to 21 per cent.

I don't attach any particular weight to the numbers, but, first of all, you are familiar generally with this chart?

DR. LOGAN: A. Yes.

Q. And if you look along the bottom, the 24 to 21, I do not mean the numbers to be accurate in any proportionate sense. It is directionally. I mean it to be used directionally only. But you do agree that moving from 24 to 21 would move the solution to the reliability problem from the right to the left in the direction shown?

A. That is correct.

Q. Now, looking at the vertical axis on the right side I have added a little arrow saying "supply cost", and is it not correct that if one moves the reserve margin from 24 to 21 and you then run up to the cost of supply curve you do in fact get a supply cost reduction as shown on the right?

A. I agree.

Q. And you have estimated the benefit of the 24 to 21 move as being -- the number that sticks in my mind is 33 to 39 million?

A. Yes.

Q. So that is your suggested reduction

that would result in supply costs of 33 to 39 million; is that correct?

A. Yes.

Q. And is it not also fair to say that the customer damage costs which result from that move would increase?

A. That's correct.

Q. And it is also fair to say, and I ask you to confirm, that nowhere in your paper do you give us a calculation that says for the suggested saving of $33 to $39 million the amount of customer damage costs which would be borne by Hydro's customer/owners would be so many dollars higher? You just haven't done that netting out to see whether overall there is a cost or a benefit in that move?

A. No, I haven't, although you can see the numbers in Table A at the end of my testimony.

Q. And what do they demonstrate?

A. Well, you have to make some interpellation here between those numbers.

Q. Well, if you have to do that then I am going to leave it. You haven't done it; it is not presented in your paper?

A. No, I haven't.

Q. Thank you.

A. But I have shown in figure 4 that the incremental benefit of the reliability of a reserve margin greater than the number that I recommend is less than the incremental cost of that higher reserve margin.

Q. All right. But my simple point is that in applying your $33 to $39 million number the Board should not view this, that number, as money out of the customer's pockets without taking into account the fact that they are going to avoid some customer damage costs if Hydro spends whatever is required to maintain a 24 per cent reserve margin?

A. That number, 38 to 39 million, will be offset somewhat by increased customer outage costs, but it won't be wiped out.

Q. But I thought you hadn't done that calculation.

A. Pardon?

Q. You have not done that calculation.

A. I have not done that calculation, but the conclusion is still obvious from figure 4 in my testimony.

Q. Just a moment. Now, I had a couple of other questions for you, Dr. Logan.

I listened to your cross-examination by

Mr. Poch, and there was a lot of discussion about externalities. My conclusion in listening to that was that all the answers with respect to externalities were given in the context of the use of customer damage costs and reserve margin considerations. Would you agree with that observation?

A. Would you run that question by me again?

Q. Yes. My conclusion in listening to your discussion with Mr. Poch --

MR. D. POCH: Mr. Chairman, I'm sorry. This is precisely why we order cross-examination, so that people like me don't get sandwiched and then have a --

THE CHAIRMAN: Well, you can ask questions following this. You will get an opportunity.

MR. D. POCH: Thank you.

MR. B. CAMPBELL: Q. My conclusion in listening to that was that all of your answers with respect to externalities were given in the context of the use of customer damage costs in reserve margin or in relation to reserve margin considerations. And I simply ask: Was I correct in that conclusion? I have tried not to be leading.

DR. LOGAN: A. Yes. I mean, ~~yes,~~ I

agree you are trying not to be leading.

THE CHAIRMAN: Well, you are entitled to be leading.

MR. B. CAMPBELL: I am sensitive to Mr. Poch's concern in this matter.

DR. LOGAN: I was not backing down on the appropriateness of applying these customer outage costs. I was hesitating a bit on all of the baggage that is associated with the term "externalities costs" being applied to these customer outage costs, which was why my discussion with Mr. Poch was as long as it was, but --

MR. B. CAMPBELL: Q. And I take it that all that baggage should not be imported into that discussion. The discussion had --

THE CHAIRMAN: Doesn't the discussion speak for itself? I think whatever the discussion is was the discussion. I think it is very hard, certainly hard for me if someone -- as to what did you say this morning, I think I have some difficulty.

If you want to refer to specific statements you can do that, but I think a general question like that is very hard for the witness to answer.

DR. LOGAN: See, the whole point of this

customer outage cost business is the customer is going to pay. Either he is going to pay in rates or he is going to pay the economic consequences of outages.

And our reliability analysis is trying to minimize those out-of-the-pocket costs to the customer, whether he is paying the utility or if he is seeing the hit on his bottom line some other way.

MR. B. CAMPBELL: Q. All right. Can I turn to Mr. Lanzalotta's evidence? I guess put at its simplest -- maybe I should start with the question of whether you recognize a distinction between operating reserve and planning reserve.

DR. LOGAN: A. Yes.

Q. Have you had the opportunity in preparing to give your testimony to review the explanation given in Panel 2 by Ontario Hydro witnesses as to the nature of those two reserves?

A. I didn't review that explicitly, but I do remember that discussion generally.

Q. All right. Perhaps you could -- perhaps the best thing to do is have you in your words explain the significance of the difference between operating and planning reserve and why that distinction is important when dealing with planning reserve matters.

A. The biggest difference between the two is the time frame.

An operating planning reserve is what the Operations Department attempts to manage from day to day or week to week or month to month in order to keep the system running, while a planning reserve margin -- well, a planning reserve margin is something that the Planning Departments aim to provide one year or five years or 20 years in the future.

There are many more uncertainties in the planning -- on the planning horizon, so the planning reserve margin necessarily has to be wider to account for those uncertainties.

Q. And, for instance, 10 minutes' spinning reserve or economy transactions that may be available for a short number of weeks or months, would they be -- is it not fair to say that those kinds of reserve considerations fall squarely within the category of operating reserve considerations?

A. Yes. Spinning reserves and 10 minute reserves are within the operating reserve category.

Q. And would you agree that they cannot be used synonymously with planning reserve considerations in a say 10 to 20 year time frame?

A. There are significant differences

between them.

Q. And it is important to recognize and account for those differences when considering planning reserve matters?

A. Yes.

MR. B. CAMPBELL: Thank you. Thank you, Mr. Chairman. Those are my questions.

THE CHAIRMAN: Mr. Poch, do you have any of questions you want to ask?

MR. D. POCH: No, I am happy with the record now, Mr. Chairman.

THE CHAIRMAN: Mr. Greenspoon, do you have any questions you want to ask?

MR. GREENSPOON: No. Thank you, sir.

THE CHAIRMAN: Anyone else have any questions?

Mr. Watson, do you have any questions you want to ask?

MR. R. WATSON: Yes, if I might, Mr. Chairman. If I could have just a minute?

RE-DIRECT EXAMINATION BY MR. R. WATSON:

Q. Very briefly Mr. Chairman. First of all, Dr. Logan, this morning Mr. Poch was asking you questions.

He started asking questions about Mr.

Lanzalotta's reserve margin, how Mr. Lanzalotta had arrived at a value of 20 per cent, and he was asking you about your value of 21 per cent, and you will recall you said there were some differences.

Could you assist the Panel with what some of those differences were?

DR. LOGAN: A. There are two key differentials in assumption and one methodological -- one major methodological difference. There may be others, but these are the ones that come to mind most readily.

One of the major differences in assumption is the nuclear outage rates. Mr. Lanzalotta's 20 per cent reserve margin included an assumption that the nuclear outage rates were increased by 50 per cent, if I recall correctly.

The second -- whereas my 21 per cent reserve margin is based upon unchanged nuclear outage rates.

The second difference in assumption relates to interconnection assistance. Mr. Lanzalotta assumes 3,200 megawatts of interconnection assistance. My 21 per cent makes the same assumption as Hydro does, 700 megawatts of interconnection assistance.

The methodological difference is that my

analysis is based on Hydro's value of service methodology while Mr. Lanzalotta's analysis starts with an earlier LOLP analysis by Hydro, an analysis that if I recall correctly is about 20 years old now. I think he quoted a 1972 statement by somebody in Hydro that you need a 30 per cent reserve margin to meet a one-day in 10 year LOLP criterion. Then he made his adjustments from there.

[3:06 p.m.]

So those are the key differences.

Q. Are those differences important, sir?

A. Yes, they are. It's coincidental that we reached the same conclusion but each of the assumptions by itself has a great effect on the target reserve margin.

Q. Dr. Logan, one more question for you. This morning Mr. Shepherd was asking you questions about common mode with respect to reserve margin. The analysis that was put forward indicated that a 51 per cent reserve margin was necessary for nuclear units. Historically has that been required in Hydro's system?

A. Well, the kind of event that this increased reserve margin is intended to cover hasn't occurred, so, no, it hasn't been required to this point

in history.

Q. Would you anticipate it would be required in the future?

A. Not on the basis of history.

Q. Mr. Koppe, near the end of Mr. Campbell's cross-examination of you, he referred you to Lakeview rehabilitation costs. Do you recall that?

MR. KOPPE: A. Yes.

Q. And he took you through the history of Lakeview in the 80s and he then asked you about the rehabilitation costs if Lakeview had been properly maintained. You looked at Lakeview costs. Did you also look at Lambton costs; and, if so, are they relevant?

A. Yes, I did and yes, they are.

Q. Could you tell the panel what the operating history of Lambton is relative to Lakeview. Did Hydro treat it the same way they treated Lakeview?

A. I don't believe so. It has certainly run more than Lakeview and it has not ever been expected that Lambton would be shut down in the near future, so there was certainly never the reason to neglect Lambton that could well have been a perfectly reasonable thing to do with Lakeview.

I think there is another factor related

both to Lambton and Lakeview and that is that while Lambton has in general been operated similarly to other plants of its general size and type, its rehabilitation costs -- the costs that are now being spent on Lambton are much higher than the average for similar plants.

And in fact while Lakeview I have no reason to doubt was neglected during the 80s, the costs that are being spent at Lakeview are much higher than what I have seen at other plants that had a similar history.

In the last few years I have done detailed investigations of about a dozen Duke power small old coal-fired units that had a very similar history: maintenance was cut back, capital spending was cut back because of a limited need for the units. And when it was eventually decided to put those units back in service and make them reliable, a considerable amount of money was spent on them but it was much less than what is being spent on Lakeview.

And the same thing is true of a couple of small Houston Lighting and Power units that I've looked at in the last year. Again, they went through a very similar situation. They were very lightly loaded. Maintenance activities were cut back to a minium. Capital spending was cut back to a minimum. And when

they were finally considered for rehabilitation and re-activation they required a substantial cost but costs on the order of a few hundred dollars a kilowatt, not six or seven hundred dollars a kilowatt.

MR. R. WATSON: Thank you, Mr. Chairman. Those are my questions.

THE CHAIRMAN: The next scheduled event is a motion being brought by Northwatch which is scheduled for November 16th. Following that, Panel 2, which is planning and assumptions, is scheduled to commence.

We have had some indication that there are matters relating to the November 16th motion that may require consideration before the motion can be argued. One, a request for subpoenas; another, Mr. Campbell's suggestion of a possible request for an adjournment.

These of course all very much play on the November -- at least on the following panel evidence. Obviously the disposition of the motion will have some effect possibly one way or the other on the continuation of the hearing.

We understand that some of these matters are under discussion amongst the parties. We would like not to be kept in the dark about them. We

certainly don't want to have to deal with pre-motion matters on the morning of November 16th and we would ask the parties to bear that in mind.

We also think that one cannot take the position that nothing has happened since Day 166 when Hydro put in its planning evidence and we would think that this process is at least owed before we start Panel 2 some evidence from Ontario Hydro, to the extent that they can give it, as to how the subsequent developments fit into the planning evidence that was given in Panel 10.

So parties should I think hold themselves in readiness between now and November 16th for the possibility of a reconvening of this hearing to deal with these or possibly other matters that come up.

There are certain days which will not be available and perhaps we should make note of those now: Thursday, November 5th, Guy Fawkes Day, is not available, not because it happens to celebrate that particular event. Nor is Friday, November 6th. Nor is November 11th, which is a holiday under the provincial legislation. Nor November 12th. Those days are not available but the others are.

If there is nothing else that anyone wishes to say at this point, we will adjourn sine die,

to use the legal expression.

THE REGISTRAR: Please come to order. This hearing will adjourn sine die.

---Whereupon the hearing was adjourned at 3:15 p.m., to be reconvened sine die.